AD-A122 644 STUDY OF THE INTERRELATIONSHIPS BETWEEN MINIMUM FLOW RELEASE POLICIES AND HYDROELECTRIC POWER DEVELOPMENT IN NEW ENGLAND(U) INTERNATIONAL ENGINEERING CO INC DARIEN CT JUN 81 1/1

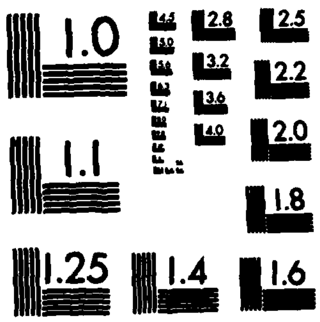
UNCLASSIFIED F/G 10/2 NL

END

DATE FILMED

2 83

DTIC


1.0
1.1
1.25
1.4
1.6
1.8
2.0
2.2
2.5
2.8
3.2
3.6
4.0

NEW ENGLAND RIVER BASINS COMMISSION

Boston, Massachusetts

Final Report

STUDY OF THE INTERRELATIONSHIPS BETWEEN MINIMUM FLOW RELEASE POLICIES AND HYDROELECTRIC POWER DEVELOPMENT IN NEW ENGLAND

June 1981

DESIGN AND CONSULTING ENGINEERS
INTERNATIONAL ENGINEERING COMPANY, INC.
A MORRISON-KNUDSEN COMPANY

UNCLASSIFIED

SECURITY CLASSIFICATION OF THIS PAGE (When Data Entered)

REPORT DOCUMENTATION PAGE		READ INSTRUCTIONS BEFORE COMPLETING FORM
1. REPORT NUMBER	2. GOVT ACCESSION NO. AD-A122644	3. RECIPIENT'S CATALOG NUMBER
4. TITLE (and Subtitle) STUDY OF THE INTERRELATIONSHIPS BETWEEN MINIMUM FLOW RELEASE POLICIES AND HYDROELECTRIC POWER DEVELOPMENT IN NEW ENGLAND		5. TYPE OF REPORT & PERIOD COVERED FINAL REPORT
		6. PERFORMING ORG. REPORT NUMBER
7. AUTHOR(s) INTERNATIONAL ENGINEERING CO., INC.		8. CONTRACT OR GRANT NUMBER(s)
9. PERFORMING ORGANIZATION NAME AND ADDRESS INTERNATIONAL ENGINEERING CO., INC. 777 POST ROAD DARIEN, CONN. 06820		10. PROGRAM ELEMENT, PROJECT, TASK AREA & WORK UNIT NUMBERS
11. CONTROLLING OFFICE NAME AND ADDRESS NEW ENGLAND RIVER BASINS COMMISSION BOSTON, MASS.		12. REPORT DATE JUNE 1981
		13. NUMBER OF PAGES 90
14. MONITORING AGENCY NAME & ADDRESS(if different from Controlling Office) U.S. ARMY CORPS OF ENGINEERS 424 TRAPELO ROAD WALTHAM, MASS. 02254		15. SECURITY CLASS. (of this report) UNCLASSIFIED
		15a. DECLASSIFICATION/DOWNGRADING SCHEDULE

16. DISTRIBUTION STATEMENT (of this Report)

DISTRIBUTION STATEMENT A
Approved for public release;
Distribution Unlimited

17. DISTRIBUTION STATEMENT (of the abstract entered in Block 20, if different from Report)

APPROVED FOR PUBLIC RELASE: DISTRIBUTION UNLIMITED

18. SUPPLEMENTARY NOTES

19. KEY WORDS (Continue on reverse side if necessary and identify by block number)

Hydroelectric power generation
New England
Hydro sites
Hydropower potential

20. ABSTRACT (Continue on reverse side if necessary and identify by block number)

This study had three basic objectives: (1) Determine the range and type of stream flow dimensions being considered for hydroelectric sites in New England, (2) Assess the interrelationships between various minimum flow regions, and (3) Identify alternative measures for complying with minimum release requirements while minimizing negative impact upon project feasibility.

DD FORM 1 JAN 73 1473 EDITION OF 1 NOV 65 IS OBSOLETE

NEW ENGLAND RIVER BASINS COMMISSION

Boston, Massachusetts

Final Report

STUDY OF THE INTERRELATIONSHIPS BETWEEN MINIMUM FLOW RELEASE POLICIES AND HYDROELECTRIC POWER DEVELOPMENT IN NEW ENGLAND

[redacted]

June 1981

DESIGN AND CONSULTING ENGINEERS
INTERNATIONAL ENGINEERING COMPANY, INC.
A MORRISON-KNUDSEN COMPANY

NERBC **New England River Basins Commission**

141 Milk Street, Third Floor
Boston, Massachusetts 02109
Tel. 617-223-6244

July 24, 1981

To Members of the NERBC Hydro Study Management Team and other Readers of this Report:

I am pleased to provide you with a copy of the final report of a minimum flow study prepared for NERBC by International Engineering Co., Inc. of Darien, CT. The study was jointly funded by NERBC and the U.S. Department of Energy.

The study was conducted to provide project applicants, consultants, and public agencies involved in the regulation of hydro development with an objective analysis of what has turned out to be a highly controversial issue in New England - minimum flow requirements at hydroelectric projects. The study was designed both to provide an assessment of the economic impacts of minimum flow requirements on the feasibility of representative hydro projects and to determine if it is possible to offset these negative impacts through the use of small turbines installed to generate electricity from the minimum flow releases. The scope of the study did not include analysis of the benefits of such releases, nor was any attempt made to evaluate the benefits of hydro development vs. protection of environmental values.

It is hoped that the results of this study will be instructive to developers and agencies involved in day to day decision making for hydro development. The study findings indicate that accomodation of minimum flow requirements may well be feasible at many sites throughout the region, particularly if the use of small turbines to generate power from minimum releases is considered and if project applicants and regulatory agencies cooperate in identifying site specific minimum flow needs.

Sincerely,

Howard Ris, Manager,
Hydropower Program

HR:ng

CONSULTING
ENGINEERS

INTERNATIONAL ENGINEERING COMPANY, INC.
A MORRISON-KNUDSEN COMPANY

EASTERN DISTRICT OFFICE
777 POST ROAD/DARIEN, CONNECTICUT 06820
PHONE: (203) 655-3345

12160
2622-110

June 8, 1981

New England River Basins Commission
141 Milk Street
Boston, Massachusetts 02109

Attention: Mr. Howard Ris, Manager, Hydro Program

Subject: Study of the interrelationships between minimum flow release policies and hydropower development in New England

Gentlemen:

I am pleased to submit our final report for the minimum flow study.

I believe that we have been able to realize the objectives of the study. The range and type of streamflow diversions being considered at New England hydro sites has been determined. The interrelationships between various minimum flow criteria and energy generation have been analyzed in detail, as well as their economic implications. Alternative measures for complying with minimum flow requirements while minimizing negative impacts upon project feasibility were explored — particularly the utilization of small turbines sized to the minimum flow release and the available head.

As instructed by the Project Management Team, the scope of this study did not address the environmental and other benefits that may result from sustained minimum flow releases.

This has been a most interesting and challenging assignment. We have enjoyed this opportunity to work with the New England River Basins Commission and the many other agencies with an interest in this study.

Very truly yours,

Carol H. Cunningham, P.E.
Project Manager

CHC:mem

[redacted]

Enclosures

TABLE OF CONTENTS

1.1 OBJECTIVES

This study of the interrelationships between alternate minimum flow release policies and hydroelectric power development in New England was performed by International Engineering Company (IECO) for the New England River Basins Commission (NERBC). The project had three basic objectives:

1. To determine the range and type of streamflow diversions being considered for hydroelectric sites in New England;

2. To assess the interrelationships between various minimum flow regimes and energy generation at representative sites through the use of case studies; and

3. Identify alternative measures for complying with minimum release requirements while minimizing negative impacts upon project feasibility.

1.2 STREAMFLOW DIVERSIONS AT ACTIVE HYDROELECTRIC SITES

Active hydroelectric sites in New England were identified by searching the files of the regional offices of the Federal Energy Regulatory Commission (FERC) and Department of Energy (DOE). Active projects were defined as those for which an application for a Preliminary Permit or License had been made and accepted within a three-year period ending January 1, 1981, or which were the subject of an application to DOE for a loan to perform a feasibility study or prepare a license application were also considered active. A total of 194 sites were identified.

Table 1-1 presents a summary of the active sites on the basis of the type of developer, type of dam, amount of head, amount of installed capacity, operating mode, and diversion length. More than half (54%) of the project developers are private non-utilities. In addition, the great majority of all projects involve an existing dam (82%), have an installed capacity of less than 5,000 kW (84%) and list their mode of operation as run-of-river (83%). More than two-thirds of the active projects have heads of less than 50 feet. About 80% of the projects propose to utilize some form of stream flow diversion, typically a penstock, headrace, tailrace, or some combination thereof. Twenty-six percent of the projects would utilize a diversion of from 1 to 300 feet, while 54% would utilize a diversion of 300 feet or more. The implications of this finding are twofold: there is a high incidence of projects in which flow conditions in a streambed may be altered by development and operation of hydroelectric facilities; and many proposed projects in New England will be affected by requirements for the maintenance of minimum flow releases in by-passed portions of stream beds and at the powerhouse.

Table 1-1

TYPES OF HYDRO PROJECTS IN NEW ENGLAND

DEVLOPER TYPE	NUMBER	PERCENT*
Private Utility	19	11
Private Nonutility	90	54
Public Utility	24	14
Public Nonutility	26	16
Hybrid	8	5
Unknown	27	
DAM TYPE		
Existing	133	82
New	30	18
Unknown	30	
HEAD		
Less than 25 feet	50	40
25 feet - 50 feet	39	31
51 feet - 100 feet	28	22
Greater than 100 feet	9	7
Unknown	69	
CAPACITY		
Less than 500 kW	50	27
500 kW - 5,000 kW	107	57
Greater Than 5,000 kW	29	16
Unknown	8	
OPERATING MODE		
Run-of-river	136	83
Peaking	24	15
Pumped storage	2	1
Tidal	1	1
Unknown	31	
DIVERSION LENGTH		
No diversion	27	20
1 foot - 300 feet	34	26
301 feet - 1,000 feet	32	24
Greater than 1,000 feet	39	30
Unknown	62	

*Percentages shown are based on the number of projects in each category for which data was available.

1.3 CASE STUDIES

Thirteen sites were selected from the list of active sites for a detailed analysis of the impact of various minimum release flow regimes on energy generation, total project costs, and overall project feasibility. Cost estimates were prepared for a range of installed capacities for each site. Average annual energy generation was then estimated for each site under the various minimum release regimes for a range of installed capacities. The energy generation studies took into account turbine-generator efficiency curves, site-specific headwater and tailwater curves, headloss in the conveyance structures, and typical maximum/minimum discharge limits of turbines.

All projects, with the exception of one site which had been designated as a peaking project and had no diversion, were assumed to operate in a strict run-of-river mode; that is, no flow would be impounded and utilized at a later time for generation. When the river flow was below the operating range of the installed equipment, it was assumed to be spilled or otherwise passed.

Three flow regimes were postulated and considered:

- No Minimum Release. This regime assumed that no minimum flow requirements would apply. All available stream flow could be diverted for power generation downstream — no releases were required to provide water in the by-passed stream bed.

- 7Q10 Flow Release. The 7Q10 flow was assumed to be released at the dam — either through a small turbine or through the spillway. The actual 7Q10 flow for each site was calculated by the U.S. Geological Survey (USGS). The 7Q10 criterion is intended to represent the lowest 7-consecutive-day mean flow expected to occur once every ten years and is commonly used as the minimum dilution flow in the design of municipal and industrial waste treatment plants.

- Aquatic Base Flow Release. The aquatic base flow (ABF) was also assumed to be released at the dam, either through a turbine or at the spillway. ABF-1 flow was defined here as the median August flow for unregulated rivers where at least 25 years of USGS streamflow records were available, or 0.5 cubic feet per second per square mile (cfsm) otherwise. ABF-2 releases were defined as 1.0 cfsm for the period January through March, 4.0 cfsm - April through June, 0.5 cfsm (or median August flow as applicable) - July through September, and 1.0 cfsm - October through December. These definitions are reasonably consistent with an interim flow release policy used by New England regional office of the U.S. Fish and Wildlife Service (USFWS). However, USFWS would probably not recommend the ABF-2 flows as described herein, but would more narrowly define the spawning and incubation seasons.

The use of small turbines to generate electricity using the various minimum release regimes was investigated for each case study site. The small

turbines were assumed to be installed at the dam and driven with the flow which had to be released in the by-passed reach of the river to satisfy the various flow regimes.

A survey of the turbine vendors indicated that most small turbines with a capacity of less than 100 kW have fixed blades. The fixed blades tend to reduce the cost of the turbines; however, they limit the turbine to a very narrow range of operating flows. Since minimum release requirements tend to be constant at a given site, fixed blade turbines are ideally suited to this application. Adjustable blade turbines were also considered when the required minimum release could drive a turbine in the 100 to 1,000 kW range. Adjustable blade turbines are more expensive than fixed blade turbines for a given runner diameter, however, they are capable of handling a flow range of about 40 to 105 percent of the rated turbine discharge. Therefore, they have the potential of generating more energy than a fixed blade turbine under varying head and flow conditions.

An optimum installed capacity for each flow regime at each site was selected on the basis of minimum capital cost per kilowatt hour of energy generated. Table 1-2 summarizes the physical characteristics of each of the case study sites as well as the cost-energy ratio for the various flow regimes, both with and without the use of small turbines. The effect that the various release regimes have on the cost-energy ratio is also shown in terms of the percentage change in this ratio. Table 1-3 summarizes the annual energy generation for each site for the various release regimes, with and without the use of small turbines.

Economic and financial evaluations of the various release regimes were made for each site from both a public (tax-exempt) and private (taxable) prospective. Life-cycle analysis and cash flow projections were made assuming a 20-year life-cycle, discount rates of 10, 15 and 20 percent, general escalation of 8 percent per year, energy escalation of 11 percent per year for 10 years and 8 percent thereafter, and a tax bracket of 50 percent for taxable entities. Investment tax credits, energy tax credits, and depreciation were also considered for the private entities. Debt service for public entities was based on 100 percent project financing at 10 percent for 30 years. A private entity was assumed to contribute 20 percent equity and finance the remaining 80 percent over a period of 20 years at an interest rate of 15 percent.

The criteria selected to evaluate the cost impact of the various minimum flow release scenarios on hydroelectric facilities was "break even" cash flow in three years for a private entity, and "break even" cash flow in five years for a public entity. These criteria are equivalent to an internal rate of return of 15 percent for a public entity and 13 percent (after taxes) for a private entity.

Table 1-4 presents the initial value of energy required by a public and private developer to meet with minimum financial and economic criteria for the various minimum release regimes for each site. These values can be compared to current market values for hydroelectric power in New England to provide an indication of how feasible each project would be under each of

Table 1-2

Summary of Energy Generation

Site	Head (ft) PH	Head (ft) Dam	Installed Capacity (kW)	Diversion Length (ft)	Average Annual Flow (cfs)	Condition Dam	Condition DCS	Condition PH	Average Annual Energy (MWh) No Minimum Release	Without Small Turbine - With Small Turbine 7Q10	ABF-1	ABF-2	Effect of Small Turbine on Energy Generation Compared to No Minimum Release 7Q10	ABF-1	ABF-2	Percent Change in Energy Generation Due to Minimum Flow Release Policy 7Q10	ABF-1	ABF-2
A	44	12	1,000	750	172	N	N	N	3,101	2,981	2,692	1,150	-	-	-	-4	-13	-63
										3,014	2,814	1,272				-3	-9	-59
B	24	16	1,000	720	934	E	E	N	6,287	5,160	3,718	1,590	-	+	-	-18	-41	-75
										6,276	7,003	4,875				0	+11	-22
C	24	12	1,000	1,200	569	M	N	N	- 5,883	5,705	4,501	2,528	-	-	-	-3	-23	-57
										5,819	5,479	3,506				-1	-7	-40
D	12	6	500	2,200	562	E	E	M	2,744	2,341	1,957	1,009	-	-	-	-15	-29	-63
										2,545	2,364	1,416				-7	-14	-48
E	38	38	8,000	0	2,024	N	-	N	35,348	34,693	30,087	26,062	+	+	+	-1	-12	-24
										35,687	43,426	39,401				+4	+26	+15
F	18	10	500	700	612	E	E	M	3,087	2,910	2,151	1,153	-	+	+	-6	-30	-63
										3,032	3,112	3,353				-2	+1	+9
G	23	12	500	240	143	E	E	E	1,803	1,614	1,458	804	-	-	-	-10	-19	-55
										1,736	1,662	1,008				-4	-8	-44
H	30	19	3,000	4,700	654	N	M	N	10,949	10,011	7,719	3,927	-	-	-	-9	-30	-64
										10,484	9,348	7,436				-4	-15	-32
I	68	16	10,000	12,000	2,316	M	N	N	70,683	31,346	52,093	26,461	-	-	-	-56	-26	-63
										41,936	57,592	39,840				-41	-19	-44
J	28	13	1,000	1,200	642	E	N	N	6,247	5,994	4,405	2,337	-	-	-	-4	-29	-63
										6,157	5,790	5,278				-1	-7	-16
K	62	5	1,500	2,200	349	E	E	E	8,326	6,937	5,358	2,786	-	-	-	-17	-36	-67
										7,328	6,230	4,632				-12	-25	-44
L	16	12	2,000	1,200	4,154	M	E	N	11,983	8,506	6,686	2,876	+	+	+	-29	-44	-76
										12,987	14,833	21,072				+8	+24	+75
M	110	25	20,000	4,700	1,515	E	N	N	78,454	72,212	60,815	32,349	-	-	-	-8	-22	-59
										73,483	70,374	41,908				-6	-10	-47

DCS - Diversion Conveyance Structure
PH - Powerhouse

E - Existing Structure
M - Major Rehabilitation Required
N - New Construction

Table 1-3

Summary of Cost-Energy Ratios

Site	Head (ft) PH	Head (ft) Dam	Installed Capacity (kW)	Diversion Length (ft)	Average Annual Flow (cfs)	Condition Dam	Condition DCS	Condition PH	Cost-Energy Ratio ($/MWh) No Minimum Release	Without Small Turbine - With Small Turbine 7Q10	ABF-1	ABF-2	Effect of Small Turbine on Cost-Energy Ratio 7Q10	ABF-1	ABF-2	Change in Cost-Energy Ratio Due to Flow Release Policy 7Q10	ABF-1	ABF-2
A	44	12	1,000	750	172	N	N	N	1,490	1,550 1,593	1,716 1,701	4,014 3,764	-	+	+	+4 +7	+15 +14	+170 +153
B	24	16	1,000	720	934	E	E	N	373	454 441	631 442	1,475 635	+	+	+	+22 +18	+69 +18	+295 +70
C	24	12	1,000	1,200	569	M	N	N	567	585 603	741 678	1,320 1,060	-	+	+	+3 +6	+31 +20	+133 +87
D	12	6	500	2,200	562	E	E	M	470	551 615	659 715	1.278 1,194	-	-	+	+17 +31	+40 +52	+172 +154
E	38	38	8,000	0	2,024	N	-	N	501	517 507	589 468	680 516	+	+	+	+2 +1	+18 -7	+36 +3
F	18	10	500	700	612	E	E	M	394	418 441	565 513	1,055 573	-	+	+	+6 +12	+43 +30	+168 +45
G	23	12	500	240	143	E	E	E	643	719 752	796 810	1,443 1,335	-	-	+	+12 +17	+24 +26	+124 +108
H	30	19	3,000	4,700	654	N	M	N	590	645 641	837 778	1,645 1,025	+	+	+	+9 +9	+42 +32	+179 +74
I	68	16	10,000	12,000	2,316	M	N	N	254	572 470	344 332	678 507	+	+	+	+125 +85	+35 +31	+167 +100
J	28	13	1,000	1,200	642	E	N	N	267	278 310	378 365	713 464	-	+	+	+4 +16	+42 +37	+167 +74
K	62	5	1,500	2,200	349	E	E	E	205	246 268	319 339	613 550	-	-	+	+20 +31	+57 +65	+200 +168
L	16	12	2,000	1,200	4,154	M	E	N	469	661 552	841 504	1,956 464	+	+	+	+41 +18	+79 +7	+317 -1
M	110	25	20,000	4,700	1,515	E	N	N	296	321 321	381 356	717 598	0	+	+	+8 +8	+29 +20	+142 +102

DCS - Diversion Conveyance Structure
PH - Powerhouse

E - Existing Structure
M - Major Rehabilitation Required
N - New Construction

Table 1-4

Summary of Initial Value of Energy Required to Meet Designated Financial Criteria

Site	Head (ft)		Installed Capacity (kW)	Diversion Length (ft)	Average Annual Flow (cfs)	Condition			Initial Value of Energy Required to Meet Designated Financial Criteria (Mills/kWh)							
									Tax-Exempt Entity Without Small Turbine / With Small Turbine				Taxable Entity Without Small Turbine / With Small Turbine			
	PH	Dam				Dam	DCS	PH	No Minimum Release	7Q10	ABF-1	ABF-2	No Minimum Release	7Q10	ABF-1	ABF-2
A	44	12	1,000	750	172	N	N	N	163	170 174	188 186	603 412	215	224 230	248 246	580 544
B	24	16	1,000	720	934	E	E	N	41	50 48	69 48	162 70	54	66 64	91 64	213 92
C	24	12	1,000	1,200	569	M	N	N	62	64 66	81 74	145 116	82	84 87	107 98	191 153
D	12	6	500	2,200	562	E	E	M	51	60 67	72 78	140 131	68	80 89	95 103	185 172
E	38	38	8,000	0	2,024	N	-	N	55	57 56	64 51	74 57	72	75 73	85 68	98 75
F	18	10	500	700	612	E	E	M	43	46 48	62 56	116 63	57	60 64	82 74	152 83
G	23	12	500	240	143	E	E	E	70	79 82	87 89	158 146	93	104 109	115 117	208 193
H	30	19	3,000	4,700	654	N	M	N	65	71 70	92 85	180 112	85	93 93	121 112	238 148
I	68	16	10,000	12,000	2,316	M	N	N	28	63 51	38 36	74 56	37	83 68	50 48	98 73
J	28	13	1,000	1,200	642	E	N	N	29	30 34	41 40	78 51	39	40 45	55 53	103 67
K	62	5	1,500	2,200	349	E	E	E	22	27 29	35 37	67 60	30	36 39	46 49	89 79
L	16	12	2,000	1,200	4,154	M	E	N	51	72 60	92 55	214 51	68	95 80	121 71	282 67
M	110	25	20,000	4,700	1,515	E	N	N	32	35 35	42 39	79 65	43	46 46	73 51	103 86

DCS – Diversion Conveyance Structure
PH – Powerhouse

E – Existing Structure
M – Major Rehabilitation Required
N – New Construction

the flow regimes. Current market values in New England are estimated to range from 50 to 90 mills per kilowatt hour based on available information from Public Utilities Commissions responsible for establishing PURPA rates in each state.

1.4 PRINCIPAL FINDINGS

The direct effect all minimum instream release regimes is to reduce the energy that can be generated at a site. This reduction increases the cost of energy generated because essentially the same capital cost must be spread over a smaller amount of energy.

Not surprisingly, the more favorable sites are better able to meet the more stringent minimum release requirements, in part due to their better economic posture prior to conforming to the release constraint. Examples of such favorable sites would include the availability of higher head at the dam, location on a high-flow river well-suited to the range of turbine-generator equipment available on the market (especially where the minimum flow release itself is sufficient for power purposes), and the availability of existing structures and equipment in reasonably good or repairable condition. Projects of these types generally remained economically feasible under the 7Q10 and ABF-1 release regimes. The ABF-2 regime was found to have a substantial negative economic impact on almost all sites.

Overall, the use of small turbines to generate power from the minimum flow releases was found to improve the economic capabilities of the projects to meet the 7Q10 of ABF requirements. However, no project employing these turbines was found to be as economically attractive as it would be in the absence of any minimum flow requirements.

1.5 USFWS ANALYSIS OF FLOW REGIMES USED IN STUDY

At the conclusion of the NERBC/IECO study, the USFWS assessed the thirteen sites to determine how closely the generic release policies used in this study would correlate with releases likely to be recommended by USFWS in actual practice. A second purpose was to determine the likelihood that USFWS would recommend maintenance flows higher than the median August flow (ABF-1) during certain times of the year to support spawning and incubation. Table 1-5 summarizes the minimum release schedules used by IECO in the study, (based on generic application of the USFWS policy) while Table 1-6 summarizes the USFWS recommendations for each site (based on site specific application of the USFWS policy).

Given the limited time available, USFWS was able to develop a specific recommendation for only four of the thirteen sites. However, for these four sites the flows the USFWS would recommend based on field observation were found to be considerably lower than those developed by IECO using the generic policy. With respect to supersedence flows (ABF-2), USFWS determined that at 87% of the sites it was unlikely that they would

TABLE 1-5

MINIMUM RELEASE REGIMES ASSUMED BY IECO

SITES	ZWIG BY-PASSED REACH Q(CFSM)	ABF-1 BY-PASSED REACH Q(CFSM)	SUPERSEDENCE SPRING Q(CFSM)	SUPERSEDENCE FALL AND WINTER Q(CFSM)
A	.05	.18	4.0	1.0
B	.18	0.5	4.0	1.0
C	.06	0.5	4.0	1.0
D	.25	0.5	4.0	1.0
E	.05	0.5	4.0	1.0
F	.09	0.5	4.0	1.0
G	.27	0.5	4.0	1.0
H	.12	0.5	4.0	1.0
I	.97	0.5	4.0	1.0
J	.06	0.5	4.0	1.0
K	.22	0.5	4.0	1.0
L	.28	0.5	4.0	1.0
M	.12	0.36	4.0	1.0

NOTES:

1. FOR ANY SITE AND ANY REGIME, THE OUTFLOW IS EQUAL TO INFLOW WHEN THE RIVER FLOW FALLS BELOW Q.
2. RELEASES AT DAM INTO BY-PASSED RIVER REACH WOULD ALSO SATISFY ANY OTHER DOWNSTREAM REQUIREMENTS REQUIRED FOR EACH SITE.
3. ABF-2 SCENARIO IS EQUAL TO ABF-1 PLUS SUPERSEDENCE FLOWS WITH ALL FLOWS RELEASED AT THE DAM.

TABLE 1-6

MINIMUM RELEASE RECOMMENDATIONS FORMULATED BY USFWS

SITES	ABF-1 DOWNSTREAM Q(CFSM)	ABF-1 DOWNSTREAM MONTHS	ABF-1 BY-PASSED REACH Q(CFSM)	ABF-1 BY-PASSED REACH MONTHS	SUPERSEDENCE SPRING Q(CFSM)	SUPERSEDENCE SPRING MONTHS	SUPERSEDENCE FALL Q(CFSM)	SUPERSEDENCE FALL MONTH
A	.24	ALL	INDET.		NONE		NONE	
B	.50	ALL	NONE		NONE		NONE	
C	.18	7/16-9/30 10/20-4/30	.18	7/16-9/30	0.5	5/1-7/15[3]	0.5	10/1-10/20[3]
D	.50	ALL	INDET.		INDET.		INDET.	
E	.25	ALL	INDET.		INDET.		INDET.	
F	.82	ALL	INDET.		NONE		NONE	
G	.50	ALL	.20	ALL	NONE		NONE	
H	.47	ALL	INDET.		NONE		NONE	
I	.46	ALL	.46[2]	ALL	NONE		NONE	
J	.50	ALL	INDET.		NONE		NONE	
K	.50	ALL	.06	ALL	NONE		NONE	
L	.50	ALL	INDET.		INDET.		INDET.	
M	.54	ALL	INDET.		INDET.		INDET.	

NOTES:

1. FOR ANY SITE AND ANY REGIME, THE OUTFLOW IS EQUAL TO INFLOW WHEN THE RIVER FLOW FALLS BELOW Q.
2. WOULD ALSO SATISFY DOWNSTREAM RELEASE REQUIREMENT.
3. AT DAM.

recommend maintenance of minimum flow releases higher than the August median flow in the by-passed reach of the river. Sixty percent of the sites studied would definitely not require supersedence releases downstream of the powerhouse.

These results suggest that the ABF release regimes used in this study may overstate the requirements likely to be recommended by USFWS. This is because they were based on strict interpretation of USFWS's generic policy, rather than site-specific, field application as would normally occur in the FERC licensing process. Furthermore, USFWS's findings also suggest that a detailed analysis may enable hydropower developers to justify minimum flow releases which are more favorable than those which would be assumed based on a strict interpretation of the USFWS generic policy.

SECTION 2

STUDY OVERVIEW

2.1 AUTHORIZATION

A request for proposals (RFP) was issued by the New England River Basins Commission (NERBC) on January 12, 1981, with proposals due on January 30, 1981. The submitted proposals were evaluated by NERBC, the U.S. Department of Energy, and the U.S. Fish and Wildlife Service. International Engineering Company (IECO) of Darien, Connecticut, was selected. IECO signed a contract with NERBC and proceeded with the project on February 20, 1981.

2.2 OBJECTIVES

As presented in the RFP, the project had three basic objectives. The first objective was to determine the range and type of streamflow diversions being considered for hydroelectric projects under development in New England. The second objective was to assess the interrelationship between various minimum flow policies and energy generation at representative hydro projects through the use of case studies. The third objective was to identify alternative measures for complying with minimum flow requirements while minimizing negative impacts upon project feasibility.

2.3 BACKGROUND

The resurgence in interest in the development of hydroelectric generating facilities in New England has been accompanied by the requirements of certain regulatory agencies for specified minimum flow releases, also known as instream releases. These releases are intended to limit the impacts of hydroelectric power operations on:

- downstream assimilation of wastes, especially where large investments have been made or are planned for industrial and municipal waste treatment;
- indigenous freshwater and anadromous fish species, which require maintenance of flow conditions for adequate migration, spawning, and juvenile development;
- downstream recreation (most importantly, white water activities such as canoeing, rafting, or kayaking); and
- streamflow aesthetics, particularly where downtown economic revitalization efforts are linked to riverine scenic attributes.

Projects operated in a strictly run-of-river mode without diversion of flow through a penstock, canal, or long tailrace generally will not be adversely impacted by minimum flow release requirements. However, minimum flow

requirements will constrain storage and release operations and will limit the amount of flow diversion to a powerhouse sited downstream to gain additional head, if some flow must be released at the base of the dam as well.

Historically, the 7Q10 standard, or the lowest 7 consecutive day mean flow expected to occur once every 10 years, has been the minimum flow requirement applied by state and federal agencies to hydroelectric projects where a requirement was imposed at all. This standard is commonly used as the minimum streamflow in the design of municipal and industrial waste treatment facilities which discharge to rivers.

The New England regional office of the U.S. Fish and Wildlife Service has recently developed an interim minimum flow release policy known as the Aquatic Base Flow (ABF). The ABF policy was designed to provide an instream release maintenance flow to protect anadromous and freshwater fishery resources during those periods of the year considered critical to migration, spawning, and incubation.

The interrelationships between these minimum flow release policies and the feasibility of hydroelectric generation has not as yet been fully examined. Almost 200 projects are proposed for FERC permitting or licensing throughout New England, and the concern has been expressed that policies based on concepts such as ABF will render most projects economically infeasible. However, proponents of these policies believe that the 7Q10 criterion is not adequate to protect fishery resources and that it is incumbent upon hydro developers to maintain adequate streamflow conditions. They argue further that if minimum flow requirements are considered prior to the sizing of equipment or selection of a design configuration, the impacts on energy output and project revenues can be minimized.

2.4 SCOPE

The project called for the completion of seven tasks. Task 1 consisted of conducting a survey of all FERC permit and license applications, DOE feasibility studies, and DOE loan applications submitted between January 1, 1978 and January 1, 1981, for sites located in the six New England states. Operating mode and flow diversion type and length were to be identified for each project. The survey would result in an inventory of active sites.

Task 2 consisted of selecting 15 sites, from the inventory assembled in Task 1, for case study analysis. Task 3 required the development of a range of minimum flow requirements for each case study site. Task 4 consisted of determining the optimum installed capacity for each case study site under each minimum flow policy. The results of Task 4 were summarized under Task 5. Generic measures of compliance were identified under Task 6. The results of the study are presented in this report, fulfilling Task 7 and the contract.

2.5 LIMITATIONS OF THE STUDY

Due to the time and budgetary constraints of this project, the scope was very narrowly defined. All viewpoints concerning minimum flow release policy could not be addressed. The approach of the study was to determine the effects of minimum flow policies upon hydro development and not the effects of hydro development upon the rivers of New England. No attempt was made to determine the benefits to the environment derived from the various policies. Therefore, the only benefits that were credited to the case study projects are the energy generation benefits.

The survey of active hydro sites is as accurate as available data will allow. Preliminary permit applications are usually filed before any feasibility study has been completed. For this reason, the information in the permit applications is inaccurate in many cases; hence, information in the survey is not totally accurate. The survey data were verified via telephone conversations with the owner or engineer, except in those cases where the owner refused to confirm the information. Nonetheless, the inventory and the analysis of it are not absolutely accurate.

A major limitation of the study is the manner in which the ABF releases were applied to the case study sites. For study purposes, all sites were treated as though significant fisheries resources were involved. However, not all sites have significant fisheries resources; and FWS would not require the ABF, as presented herein, at those sites.

2.6 ACKNOWLEDGEMENTS

IECO wishes to thank the NERBC Program Manager in particular and the Project Management Team and the Study Task Force in general for their support and assistance. In addition, the cooperation received in the form of specific project information from the several developers and, their consulting engineers in some cases, is greatly appreciated.

SECTION 3

INVENTORY OF ACTIVE SITES

3.1 STUDY METHODOLOGY

As part of its contract with NERBC, IECO prepared an inventory of active hydroelectric generation sites in New England. Active sites were defined as those sites for which either outstanding preliminary permits or applications for preliminary permits, licenses, or exemptions are on file with FERC; or for which applications have been made to DOE for a feasibility study or licensing loan. Those projects already licensed were excluded. Sites for which competing applications have been filed were also identified. The application for a site accepted earliest by FERC has been used for purposes of this study as the proposed development.

The first step in preparing the inventory was to design a one-page data sheet, which IECO engineers could use to guide and record their research efforts. A blank data sheet is presented as Figure 3-1. Use of the data sheet ensured a consistent approach to the data acquisition effort. The data sheet was approved by the NERBC Program Manager prior to survey completion.

Using the data sheet, IECO engineers searched the files of the New York regional office of the Federal Energy Regulatory Commission (FERC). Data sheets were completed from each application submitted to that office between January 1, 1978, and January 1, 1981. If an application for a preliminary permit, exemption, or license included more than one site, a data sheet was prepared for each site.

The Region I office of the U.S. Department of Energy (DOE) also assisted in completing the inventory. A list of all sites for which applications for a feasibility study loan or licensing loan had been made during the applicable period was provided to IECO. The list was cross-checked against the FERC list of sites, and a data sheet was prepared for each site not represented on the FERC list.

The data in the inventory was based, for the most part, on information contained in FERC preliminary permit applications. Often, the information that appears in a typical permit application is not an accurate representation of the final hydro development. Information is sketchy because a feasibility study has not yet been prepared. Many of the figures are estimates. Terminology, such as run-of-river, varies in meaning from one developer to the next. Although attempts were made to verify all information contained in the survey, inaccuracies still exist.

Using the data sheets, a preliminary list of sites was prepared (the inventory) and was presented to NERBC. IECO engineers attempted to fill in missing data and confirm the information in the inventory by contacting site owners or developers by telephone. This effort was, for the most part, successful. The final inventory was then prepared.

PROJECT NAME ____________ STATE ________ FERC NO. ________

DATE OF FERC NOTICE ____________ FERC STATUS ________ NERBC NO. ________

FERC NO. COMPETING APPLICATIONS ____________ CLOSING DATE ________ COE NO. ________

APPLICANT: ____________ STATE NO. ________

IECO NO. ________

DOE NO. ________

DEVELOPER: ____________ PRINCIPAL CONTACT: ____________

OWNER: ____________ ENGINEER: ____________

DEVELOPER CATEGORY: PUBLIC PRIVATE UTILITY NONUTILITY HYBRID ____________

LOCAL UTILITY ____________ PROBABLE PURCHASER OF POWER ____________

RIVER ________ NERBC BASIN ________ LAT N ________ LONG W ________

COMMUNITY ________ COUNTY ________ USGS QUAD NAME ________

TYPE OF DAM: EXISTING NEW SITE CONCRETE GRAVITY MASONRY EARTHEN TIMBER CRIB OTHER ________

HEIGHT ________ HEAD ________ Q_{AVE} ________ 7Q10 ________ DRAINAGE AREA ________

CAPACITY ________ ANNUAL ENERGY ________ PLANT FACTOR ________ OPERATION P ROR

IMPOUNDMENT AREA ________ NEAREST USGS GAGE ________ PRESENT RESERVOIR USES ________

PENSTOCK LENGTH ________ HEADRACE CANAL LENGTH ________ TAILRACE LENGTH ________

SKETCH PROPOSED DEVELOPMENT ON REVERSE OR PHOTOCOPY AND ATTACH. HIGHLIGHT DIVERSIONS

PHOTOCOPY CORRESPONDENCE CONCERNING MINIMUM FLOWS:

BRIEFLY COMMENT ON QUANTITY OF INFORMATION AVAILABLE: ____________

COMMENT ON STATUS OR AVAILABILITY OF THE FOLLOWING:

COE DAM SAFETY REPORT ____________

FLOOD INSURANCE STUDY ____________

NERBC FILE ____________

COE FILES ____________

TOPOGRAPHIC MAPS ____________

FISH AND WILDLIFE REPORTS ____________

WILD AND SCENIC RIVERS STATUS ____________

HISTORIC DESIGNATION STATUS ____________

STATE DAM SAFETY FILE ____________

AVAILABLE REPORTS (APPRAISAL, FEASIBILITY, EIS, EA, OTHER) ____________

OTHER INFORMATION: ____________

Figure 3-1. Data Sheet

3.2 ACTIVE SITES IN NEW ENGLAND

A total of 194 active hydro sites in New England was identified for which 210 applications had been filed. The 194 sites were categorized in the inventory by developer type, dam type, feet of head, capacity, operating mode, and length of diversion as shown in Table 3-1. Table 3-2 is a summary of this information. Other applications for the same site are identified in Table 3-1 by an asterisk and are not been included in the results presented in Table 3-2.

Private developers have filed a large percentage of the permit, license, and loan applications (66 percent). This reflects the many incentives for private hydro development, such as tax treatment and PURPA rates. However, many of those categorized as private and public developers are private and public utilities. This reflects the interest in hydro which utilities have.

The large percentage of proposed hydro developments involving existing dams reflects the large number of dams in New England and the difficulty small hydro has in supporting new dam construction due to the high capital cost and relatively low annual energy that can be generated at a small site.

The analyses of head and capacity indicate that most sites have less than 100 feet of head and that few sites can support more than 5,000 kW of installed capacity.

Operating mode and diversion length are the most critical items relative to minimum flow releases. Minimum flow releases have little or no impact upon sites that operate in the run-of-river mode and have no diversions. Only 20 percent of all sites have no diversion. Even if all 20 percent are run-of-river sites, the potential occurrence of conflicts is about 80 percent; that is, at 80 percent of the sites proposed for development, the potential exists for conflict between hydro development and minimum flow requirements.

If minimum flow releases were allowed to be made within 300 feet of the dam, the conflict incidence would decrease. Sites that have diversions less than or equal to 300 feet account for 46 percent of all sites. This reduces the conflict incidence to about 54 percent of all sites.

Fifteen percent of all sites are proposed as peaking facilities. Peaking facilities conflict with minimum flow requirements due to the store-and-release nature of this mode of operation. The store phase eliminates or drastically reduces flow in the river and the release phase can result in very high velocities in the river.

Table 3-1

INVENTORY OF ACTIVE HYDRO SITES

CONNECTICUT

PROJECT NAME	RIVER	FERC NO.	FERC STATUS	DEV. CAT.	TYPE DAM	HEAD FT	INSTALLED CAPACITY KW	OPERATION MODE	PENSTOCK LENGTH	HEADRACE LENGTH	TAILRACE LENGTH
DERBY	HOUSATONIC	2996	PON UD	PRI-UT	EXIST	26	8,000	ROR	0	100	0
WINDSOR LOCKS	CONNECTICUT	3049	PAN	PRI-NON	EXIST		5,000	ROR		27,980	
WAREHOUSE POINT*	CONNECTICUT	3183	PAP U	PRI-UT	NEW		50,000	ROR			4,600
GOODWIN	FARMINGTON	3270	PAN UD	PRI-NON	EXIST	110	3,200	ROR	300		
COLEBROOK	FARMINGTON	3270	PAN UD	PRI-NON	EXIST						
COLLINS UPPER	FARMINGTON	3271	PAN UD	PRI-NON	EXIST	200	3,000	ROR			
COLLINS LOWER	FARMINGTON	3271	PAN UD	PRI-NON	EXIST	200	3,000	ROR			
TARIFFVILLE	FARMINGTON	3324	PAN U	PRI-UT	EXIST	30	1,500	ROR	0	0	0
WEST THOMPSON LAKE	QUINEBAUG	3424	PAN UD	PRI-NON	EXIST	45	2,260	ROR	900	0	50
THOMASTON	NAUGATUCK	3425	PAN UD	PRI-NON	EXIST		2,750	ROR	500	0	150
MANSFIELD HOLLOW	NAUGATUCK	3463	PAN UD	PRI-NON	EXIST	42	2,000	ROR	500	0	150
WYRE WYND	QUINEBAUG	3472	PAP	PRI-NON	EXIST	19	1,200	ROR			
QUINEBAUG	QUINEBAUG	3646	PAN UD	PRI-NON	EXIST	30	1,450	ROR			
WAUREGAN MILLS											
EAGLEVILLE							400				
FALLS MILLS							970				
GREENWOODS							1,600				
ASHLAND POND							344				

KEY:
* - COMPETING APPLICATION

FERC STATUS
EAR - EXEMPTION APPLICATION REJECTED
ESH - EXEMPTION APPLICATION PENDING
MAN - MAJOR LICENSE-APPLICATION PENDING NON-PUBLIC
MAP - MAJOR LICENSE-APPLICATION PENDING PUBLIC
NAN - MINOR LICENSE-APPLICATION PENDING NON-PUBLIC
NAP - MINOR LICENSE-APPLICATION PENDING PUBLIC
PAN - PERMIT APPLICATION PENDING NON-PUBLIC
PAP - PERMIT APPLICATION PENDING PUBLIC
PON - PERMIT APPLICATION OUTSTANDING NON-PUBLIC
POP - PERMIT APPLICATION OUTSTANDING PUBLIC

DEVELOPMENT CATEGORY
HYBRID - JOINT: PRIVATE AND PUBLIC
PRI-NON - PRIVATE NON UTILITY
PRI-UT - PRIVATE UTILITY
PUB-NON - PUBLIC NON UTILITY
PUB-UT - PRIVATE UTILITY

OPERATION MODE
P - PEAKING OPERATION
PS PUMPED STORAGE OPERATION
ROR - RUN OF RIVER OPERATION

Table 3-1

INVENTORY OF ACTIVE HYDRO SITES (Continued)

MAINE

PROJECT NAME	RIVER	FERC NO.	FERC STATUS	DEV. CAT.	TYPE DAM	HEAD FT	INSTALLED CAPACITY kW	OPERATION MODE	PENSTOCK LENGTH	HEADRACE LENGTH	TAILRACE LENGTH
NORTH ANSON	CARRABASSET	2830	POP U	PUB-UT	NEW	30	5.500	ROR			
CARRABASSETT	CARRABASSET	2830	POP U	PUB-UT	NEW	67	12.000	ROR			
MADISON	KENNEBEC	2830	POP U	PUB-UT	NEW	25	18.000	ROR			
BIG SANDY	BIG SANDY	2830	POP U	PUB-UT	EXIST	40	10.000	ROR			
SOMERSET	BIG SANDY	2830	POP U	PUB-UT	NEW	92	22.500	ROR			
MASARDIS	AROOSTOOK	3057	PON U	PRI-UT	NEW	90	10.000	P	0	0	10
CASTLE HILL	AROOSTOOK	3057	PON U	PRI-UT	NEW	60	18.000	P	0	0	10
GORDON FALLS	MATTAWAMKEAG	3236	PON U	PRI-NON	NEW	40	15.900	ROR	0	0	250
ARCHES	WEST BRANCH PENOBSCOT	3237	PAN U	PRI-NON	NEW	90	33.600	ROR	4.500	0	0
MARSH ISLAND	PENOBSCOT	3238	PAN U	PRI-NON	NEW		29.600	ROR	0	0	0
BASIN MILLS*	PENOBSCOT	3325	PAN U	PRI-NON	NEW	28	30.000	ROR	0	0	50
WORUMBO MILLS	ANDROSCOGGIN	3428	PAN UD	PRI-NON	EXIST	33	14.000	ROR	0	100	500
GREAT WORKS	GREAT WORKS	3444	PAN UD	PRI-NON	EXIST		300	ROR	280	0	0
UPPER BARKER'S MILL	LITTLE ANDROSCOGGIN	3562	PAN U	PRI-NON	EXIST	26	950	ROR	6	0	0
PEJEBSCOT	ANDROSCOGGIN	3631	PAN	PRI-NON	EXIST	22	10.000	ROR	0	50	0
BENTON FALLS	SEBASTICOOK	3632	PAN U	PRI-NON	EXIST	28	2.800	ROR		260	150
EAST MACHIAS	EAST MACHIAS	3688	NAN UD	PUB-NON	EXIST	24	1.500	ROR	1.100		
BIG A*	WEST BRANCH PENOBSCOT	3779	PAN U	PRI-NON	EXIST	137	34.100	ROR	7.000	0	0
SEBEC	SEBEC	3793	PAN UD	PRI-NON	EXIST		1.000	ROR	850	0	0
LITTLEFIELD	LITTLE ANDROSCOGGIN	3935	PAN U	PRI-NON	EXIST	21	1.000	ROR	0	0	0
SWIFT RIVER	PENOBSCOT	3986	PAN U	PRI-NON	EXIST	14.5	13.000	ROR			
AZISCOHOS*	MAGALLOWAY	4013	PAN UD	PRI-NON	EXIST	55	1.600	ROR	0	0	0
UPPER DAM	MOOSELOOK-MEGUNTIC	4022	PAN UD	PRI-UT	EXIST	15	1.500	ROR	0	0	0
RANGELEY	RANGELEY	4025	PAN UD	PRI-UT	EXIST	7.5	300	ROR	0	0	0
AZISCOHOS	MAGALLOWAY	4026	PAN UD	PRI-UT	EXIST	41	2.500	ROR	0	0	0
MIDDLE DAM	RAPID	4027	PAN UD	PRI-UT	EXIST	14	1.500	ROR	0	0	0
SACO FALLS							1.360				
SMELT HILL							1.300				

Table 3-1

INVENTORY OF ACTIVE HYDRO SITES (Continued)

MASSACHUSETTS

PROJECT NAME	RIVER	FERC NO.	FERC STATUS	DEV. CAT.	TYPE DAM	HEAD FT	INSTALLED CAPACITY KW	OPERATION MODE	PENSTOCK LENGTH	HEADRACE LENGTH	TAILRACE LENGTH
TEXON	WESTFIELD	2986	PON	PRI-NON	EXIST	28.5	1.360	ROR	0	36	50
CENTENNIAL ISLAND	CONCORD	2958	PON UD	PRI-NON	EXIST	22	620	ROR	0	2500	90
LITTLEVILLE	MIDDLE BRANCH WESTFIELD	3003	PUP UD	PUB-NON	EXIST	90	760	ROR	900	0	0
MILLERS ONE	MILLERS	3061	PUP U	PUB-UT	NEW	10	2.000	ROR	0	2000	0
MILLERS TWO	MILLERS	3061	PUP U	PUB-UT	NEW	45	4.000	ROR			
MILLERS THREE	MILLERS	3061	PUP U	PUB-UT	NEW	20	1.300	ROR			
MILLERS FOUR	MILLERS	3061	POP U	PUB-UT	NEW		1.800	ROR			
MILLERS FIVE	MILLERS	3061	PUP U	PUB-UT	NEW		2.000	ROR			
STEVENS UPPER	LITTLE	3103	PUP U	PUB-UT	EXIST	10	0	P	0	0	0
STEVENS LOWER	LITTLE	3103	PUP U	PUB-UT	EXIST	15	500	P	0	0	0
STILLWATER BRIDGE	DEERFIELD	3123	PUP U	PUB-UT	NEW	58	11.000	ROR	40	0	20
WARE	WARE	3127	PON UD	PRI-NON	EXIST	47	1.050	P	350	500	20
NATIONAL UPPER	SWIFT	3166	PON UD	PRI-NON	EXIST	15	125	ROR	0	600	100
NATIONAL LOWER	SWIFT	3166	PON UD	PRI-NON	EXIST	12	125	ROR	0	430	200
HADLEY NO. 3	CONNECTICUT	3283	PAP UD	PUB-UT	EXIST	52	45.000	ROR	0	0	3.000
RIVERDALE	BLACKSTONE	3297	PON UD	PRI-NON	EXIST	10	280	ROR	0	100	1.500
PLEASANT STREET	CHARLES	3318	PON UD	PRI-NON	EXIST	10	250	ROR	0	960	100
KNIGHTVILLE	WESTFIELD	3337	PAN UD	PRI-NON	EXIST	114	3.940	ROR	700	0	0
WESTVILLE	QUINEBAUG	3339	PAN UD	PRI-NON	EXIST	53	1.550	ROR	200	0	50
BARRE FALLS	WARE	3340	PAN UD	PRI-NON	EXIST	78	1.160	ROR	550	0	300
BIRCH HILL	MILLERS	3423	PAN UD	PRI-NON	EXIST	33	670	ROR	450	0	50
NEEDHAM	CHARLES	3465	PAN UD	PRI-NON	EXIST	9	165	ROR	0	0	0
COLLINS	CHICOPEE	3506	PAP U	PUB-UT	EXIST	14	1.000	ROR	0	1.000	400
SILK MILL	CHARLES	3805	PAN UD	HYBRID	EXIST		300	ROR			
CIRCULAR	WEWEANTIC	3805	PAN UD	HYBRID	EXIST		300	ROR			
TREMONT		3894	ESH UD	PUB-NON	EXIST	22	300	ROR	0	0	0
AMESBURY							500				
CHARLES RIVER BASIN							450				
MIDDLEBORO							280				
CRYSTAL LAKE							180				
CHICOPEE				PUB-UT	EXIST	26	2.500	ROR	0	0	500

Table 3-1

INVENTORY OF ACTIVE HYDRO SITES (Continued)

NEW HAMPSHIRE

PROJECT NAME	RIVER	FERC NO.	FERC STATUS	DEV. CAT.	TYPE DAM	HEAD FT	INSTALLED CAPACITY KW	OPERATION MODE	PENSTOCK LENGTH	HEADRACE LENGTH	TAILRACE LENGTH
SURRY MOUNTAIN	ASHUELOT	2819	PON UD	PRI-UT	EXIST			ROR	383	748	0
OTTER BROOK	OTTER BROOK	2819	PON UD	PRI-UT	EXIST			ROR	540		
WEST MILAN	AMMONOOSUC	3825	PON U	PRI-NON	NEW	220	4,000,000	PS			
KILKENNY	UPPER AMMONOOSUC	2825	PON U	PRI-NON	NEW						
PONTOOK	ANDROSCOGGIN	2861	PON UD	PRI-NON	EXIST	62	9,800	ROR	330	4,200	2,000
MONADNOCK	SUGAR	2944	POP UD	HYBRID	EXIST		1,500	ROR			
SULLIVAN	SUGAR	2944	POP UD	HYBRID	EXIST		1,500	ROR	1,800	0	30
LAYFAYETTE	SUGAR	2944	POP UD	HYBRID	EXIST		1,500	ROR	600	0	20
SEWALL'S FALLS*	MERRIMACK	2965	PAN UD	PRI-NON	EXIST	16	4,275	ROR	0	1,200	0
CLEMENT	WINNEPESAUKEE	2966	PON U	PRI-NON	EXIST		1,000	ROR	200	200	0
LOCHMERE	WINNEPESAUKEE	2982	PAP UD	PRI-NON	EXIST	16	800	ROR	500	0	0
MURPHY	CONNECTICUT	3006	PAN UD	PRI-UT	EXIST	80	2,000	ROR	320	0	400
KELLY'S FALLS*	PISCATAQUOG	3025	NAN UD	PRI-NON	EXIST	24	1,000	P	60	0	0
KELLY'S FALLS	PISCATAQUOG	3039	PAP UD	PUB-NON	EXIST	22	500	ROR	90	0	0
SEWALL'S FALLS	MERRIMACK	3040	PAP-UD	PUB-NON	EXIST	16	2,850	ROR	0	1,200	0
STEELE POND	NORTH BRANCH CONTOOCOOK	3087	PAN-UD	PRI-NON	EXIST	84	500	ROR	1,600	0	50
FRANKLIN 8	WINNEPESAUKEE	3093	NAN UD				1,000				
MOORE'S FALLS	MERRIMACK	3094	PON U	HYBRID	NEW		21,000	P	0	400	250
NEWFOUND	NEWFOUND	3107	NAN UD	PRI-NON	EXIST	90	1,487	ROR	420	220	175
FRANKLIN FALLS	WINNEPESAUKEE	3118	PAN UD	PRI-NON	EXIST	93	3,000	ROR	5,000	0	0
LOCHMERE*	WINNEPESAUKEE	3128	PAP UD	PUB-NON	EXIST		1,000	ROR	500	60	0
ROLLINSFORD	SALMON FALLS	3132	NAN UD	PRI-NON	EXIST		1,300	ROR	600	0	0
ERROL	ANDROSCOGGIN	3133	PON UD	HYBRID	EXIST	19	2,500	ROR	0	160	0
FRANKLIN	WINNEPESAUKEE	3170	PAN UD								
LAKE FRANCIS	CONNECTICUT	3176	PAP UD	PUB-NON	EXIST		2,200	ROR	360	0	600
WEBSTER MILL	SUNCOOK	3179	NAN UD	PRI-NON	EXIST	52	1,860	ROR	920	500	0
GREGGS FALLS	PISCATAQUOG	3180	PAP UD	PUB-NON	EXIST		1,500	ROR	0	0	0
PEMBROKE	SUNCOOK	3185	PAN UD	PRI-NON	EXIST			ROR			
WEBSTER*	SUNCOOK	3185	PAN UD	PRI-NON	EXIST			ROR	240		
COTTON MILL	WINNEPESAUKEE	3221	PON UD	PRI-NON	EXIST	11.5	400	ROR	15	0	0
SOUTH MILTON	SALMON FALLS	3222	PAN	PRI-NON	EXIST	10	2,400	ROR	4,000	0	150
JACKSON MILLS	NASHUA	3225	NAP UD	PUB-NON	EXIST	21	1,300	ROR	0	40	0
CAMPTON	MAD	3233	PON UD	PRI-NON	EXIST	33	300	ROR	600	0	20
ROLFE CANAL	CONTOOCOOK	3240	PON U	PRI-NON	EXIST	22	2,200	ROR	0		200
SEWALL'S FALLS*	MERRIMACK	3254	PAN UD	PRI-UT	EXIST	15	4,000	ROR	0	1,280	0
STEELE POND*	NORTH BRANCH CONTOOCOOK	3265	PAP UD	PUB-NON	EXIST	73	570	ROR	1,800	0	0
MILTON LEATHER	SALMON FALLS	3269	PAN UD	PRI-NON	EXIST	21	1,400	ROR	0	0	0
ASHUELOT	ASHUELOT	3284	PAN	PRI-NON	EXIST	68	3,100	ROR	4,000	0	50
PENACOOK	CONTOOCOOK	3299	PAN	PRI-NON	EXIST		1,530	ROR	40	0	0
FRANKLIN FALLS	PEMIGEWASSET	3301	PON	PRI-NON	EXIST	85	5,000	ROR	1,750	0	0
SURRY MOUNTAIN*	ASHUELOT	3302	PAN	PRI-NON	EXIST		1,480	ROR	1,400	0	0
BLACK WATER	BLACKWATER	3303	PAN	PRI-NON	EXIST	30	443	ROR	0	0	0
NASH MILL	ASHUELOT	3309	PON UD	PRI-NON	NEW	55	50	ROR	1,500	0	0
LAKEPORT	WINNEPESAUKEE	3312	PAP UD	PUB-NON	EXIST	10	320	ROR	0	0	60

Table 3-1

INVENTORY OF ACTIVE HYDRO SITES (Continued)

NEW HAMPSHIRE (Continued)

PROJECT NAME	RIVER	FERC NO.	FERC STATUS	DEV. CAT.	TYPE DAM	HEAD FT	INSTALLED CAPACITY kW	OPERATION MODE	PENSTOCK LENGTH	HEADRACE LENGTH	TAILRACE LENGTH
CAPLAN	SUGAR	3320	PAN UD	PRI-NON	EXIST		150	ROR			
INTERNATIONAL SHOE	SUGAR	3320	PAN UD	PRI-NON	EXIST		180	ROR			
BROMPTON	SUGAR	3320	PAN UD	PRI-NON	EXIST		120	ROR			
PENACOOK LOWER	CONTOOCOOK	3342	PAN UD	PRI-NON	EXIST		3,000	ROR	0	0	450
PENACOOK UPPER	CONTOOCOOK	3343	PAN UD	PRI-NON	EXIST		2,200	ROR	0	0	250
PENACOOK	CONTOOCOOK	3402	PAN UD	PRI-NON	EXIST		1,960	ROR	2900	0	100
EVERETT	CONTOOCOOK	3426	PAN UD	PRI-NON	EXIST	34	215	ROR	1200	0	0
HOPKINTON	PISCATAQUOG	3426	PAN UD	PRI-NON	EXIST		800	ROR	1350	0	375
MINE FALLS	NASHUA	3442	PUP UD	PUB-NON	EXIST	32	1,360	ROR	500	0	0
CP STEVENS	WINNEPESAUKEE	3454	PAN	PRI-			492				
LISBON	AMMONOOSUC	3464		PRI-NON	EXIST		850	ROR	0	200	50
PENNICHUCK	SOUHEGAN	3561		PRI-NON	EXIST	21	471	ROR	0	200	0
LIVERMORE FALLS	PEMIGEWASSET	3572	PAN U	PRI-NON	EXIST	37	1,400	ROR	0	0	0
BRANCH RIVER MILL	BRANCH	3615	PAN	PRI-NON	EXIST		30	ROR	0	0	0
NOONE MILLS	CONTOOCOOK	3616	PAN UD	PRI-NON	EXIST	21	280	ROR	0	0	0
FRANKLIN MILLS	WINNEPESAUKEE	3760	NAN UD	PRI-NON	EXIST	27	1,250	ROR	800	0	0
ROLLINSFORD*	SALMON FALLS	3777	NAP UD	PUB-NON	EXIST	45	1,490	ROR	600	30	0
SALMON FALLS	SALMON FALLS	3820	NAN UD	PRI-NON	EXIST	62	1,500	ROR	500	1650	100
GILES JOLEZ	SALMON BROOK	3822	PAN UD	PRI-NON	EXIST	92	350	ROR	1,000	0	50
SOUTH MILTON*	SALMON FALLS	3984	ESH UD	PRI-NON	EXIST	102	1,000	ROR	3,800	0	150
NORTH ROCHESTER*	SALMON FALLS	3985	ESH UD	PRI-NON	EXIST	25	250	ROR	0	1,000	1,000
SUGAR RIVER						3,500					
WOODSVILLE						500					
HOSIERY MILL	CONTOOCOOK			PUB-NON	EXIST	23	1,000	ROR	0	0	270
PISCATAQUA RIVER							4,000	TIDAL			
LINCOLN							2,200				
LOWER ROBERTSON							1,400				
BETHLEHEM MINK FARM							750				

Table 3-1

INVENTORY OF ACTIVE HYDRO SITES (Continued)

RHODE ISLAND

PROJECT NAME	RIVER	FERC NO.	FERC STATUS	DEV. CAT.	TYPE DAM	HEAD FT	INSTALLED CAPACITY kW	OPERATION MODE	PENSTOCK LENGTH	HEADRACE LENGTH	TAILRACE LENGTH
BRADFORD	SOUTH BRANCH PAWCATUCK	2974	PON UD	PRI-NON	EXIST	8	215	ROR	0		
ANTHONY POND	SOUTH BRANCH PAWTUXET	3007	PON UD	PRI-NON	EXIST	14	0	ROR	0	0	0
QUIDNICK UPPER	SOUTH BRANCH PAWTUXET	3008	PON UD	PRI-NON	EXIST		150	ROR	0	650	570
CROMPTON UPPER	SOUTH BRANCH PAWTUXET				EXIST	10	85	ROR	0	4,000	10
CROMPTON LOWER	SOUTH BRANCH PAWTUXET	3009	PON UD	PRI-NON	EXIST	18	185	ROR	0	2500	100
CENTERVILLE	SOUTH BRANCH PAWTUXET	3010	PON UD	PRI-NON	EXIST	20	220	ROR	0		
ARCTIC	SOUTH BRANCH PAWTUXET	3011	PON UD	PRI-NON	EXIST	28	310	ROR	0		
RIVERPOINT	SOUTH BRANCH PAWTUXET	3012	PON UD	PRI-NON	EXIST	27	300	ROR	0		
NATICK POND	PAWTUXET	3013	PON UD	PRI-NON	EXIST	30	260	ROR			
ELIZABETH	BLACKSTONE	3057	NAN UD	PRI-NON	EXIST	9.5	670	ROR	0	40	250
CENTRAL FALLS	BLACKSTONE	3063	NAN UD	PRI-NON	EXIST	14	900	ROR	0	300	1,200
GRISWOLD	PAWCATUCK	3268	PON UD	PRI-NON	EXIST	12	500	ROR	0	2000	2,000
HUNT'S MILL	TEN MILE	3431	PAP UD	PUB-NON	EXIST	34	280	ROR	2200	0	100
STAMINA MILL	BRANCH	3531	PAN UD	PRI-NON	EXIST	15	237	ROR	0	0	0
TURNER RESERVOIR							285				
HARRISVILLE							220				
MANVILLE							1,240				

Table 3-1

INVENTORY OF ACTIVE HYDRO SITES (Continued)

VERMONT

PROJECT NAME	RIVER	FERC NO.	FERC STATUS	DEV. CAT.	TYPE DAM	HEAD FT	INSTALLED CAPACITY KW	OPERATION MODE	PENSTOCK LENGTH	HEADRACE LENGTH	TAILRACE LENGTH
HAWKS MOUNTAIN	BLACK	2750	MAP U	PUB-NON	NEW	155	15.500	P	800	0	0
COVERED BRIDGE	BLACK	2750	MAP U	PUB-NON	NEW	30	3.100	P	0	0	0
TOLLES HILL	BLACK	2750	MAP U	PUB-NON	EXIST	30	3.100	P	0	40	120
GILMAN	BLACK	2750	MAP U	PUB-NON	NEW	30	3.100	P	170	0	75
COMPTU FALLS	BLACK	2750	MAP U	PUB-NON	EXIST	30	3.100	P	70	0	0
LOVE JOY	BLACK	2750	MAP U	PUB-NON	EXIST	30	3.100	P	900	0	0
CHACE MILL	WINOOSKI	2756	MAN UD	PUB-UT	EXIST	56	13.000	ROR	2.000	0	0
EAST GEORGIA	LAMOILLE	2762	MAN U	PRI-UT	NEW	52	14.000	P	0	0	0
NORTH HARTLAND	OTTAUQUECHE	2816	MAN UD	PUB-UT	EXIST	58	4.000	P	470	0	400
UNION VILLAGE	OMPOMPANOOSAC	2819	PON UD	PRI-UT	EXIST						
BALL MOUNTAIN	WEST	2838	POP UD	PUB-NON	EXIST	25	20.000	P			
TOWNSHEND	BLACK	2838	POP UD	PUB-NON	EXIST	25	4.000	P			
WEST DUMMERSTON	WEST	2838	POP UD	PUB-NON	EXIST	26	1.000	P	0	0	0
NORTH BRANCH BROOK	NORTH BRANCH BROOK	2838	POP UD	PUB-NON	NEW		1.000	P	5.200		
ROCK RIVER	ROCK	2838	POP UD	PUB-NON	NEW		1.000	P	1.900	0	0
HART ISLAND	CONNECTICUT	2855	POP U	PUB-NON	EXIST	24	15.000	ROR			
NORTH SPRINGFIELD	BLACK	2872	POP UD	PUB-NON	EXIST	18	1.000	P	1.000	50	100
BOLTON FALLS	WINOOSKI	2879	MAN UD	PRI-UT	EXIST		6.500	ROR	100	0	600
SAXTONS RIVER	SAXTON	2893	NAN U	PRI-NON	NEW	70	1.500	P	960	0	60
JAY BRANCH	MISSISQUOI	2905	PON U	PUB-UT	NEW	166	22.000	P	2.000	0	200
NORTH TROY	MISSISQUOI	2905	PON U	PUB-UT	EXIST	22	400	ROR	2.000		40
ENOSBURG FALLS	MISSISQUOI	2905	PON U	PUB-UT	EXIST	20	2.600	ROR	0	120	200
NORTH SHELDON	MISSISQUOI	2905	PON U	PUB-UT	NEW	28	6.000	P	0	0	200
SHELDON SPRINGS	MISSISQUOI	2905	PON U	PUB-UT	EXIST	110	25.000	P	2.600	0	100
HIGHGATE FALLS	MISSISQUOI	2905	PON UD	PUB-UT	EXIST	76	9.400	ROR			
FROG HOLLOW	OTTER CREEK	2947	PON UD	PRI-UT	EXIST	23	1.500	ROR	0	160	80
MORETOWN 8	MAD	3020	PON UD	PRI-NON	EXIST	41	900	ROR	0	0	20
EAST BARNETT	PASSUMPSIC	3051	PON UD	PRI-UT	EXIST	29	2.200	ROR			
VAIL STATION	PASSUMPSIC	3090	NAP	PUB-UT	EXIST	20	350	ROR	0	0	0
AMERICAN WOOLEN	WINOOSKI	3101	PAP U	PUB-NON	EXIST	20	1.200	ROR	100	0	0
RYEGATE	CONNECTICUT	3117	PON U	PRI-NON	EXIST	12	5.000	ROR	0	0	100
BROCKWAYS MILLS	WILLIAMS	3131	PON U	PRI-NON	EXIST	90	1.000	ROR	2.000	0	0
DEWEYS MILL	OTTAUQUECHEE	3214	PAN UD	PRI-NON	EXIST		1.500	ROR	100	0	0
EMERY MILLS	OTTAUQUECHEE	3215	PAN UD	PRI-NON	EXIST		750	ROR			
POWNAL TANNING	HOOSIC	3264	PON UD	PRI-NON	EXIST	18	500	ROR	110	0	0
DOWNER MILL	OTTAUQUECHEE	3744	PAN UD	PRI-NON	EXIST	29	800	ROR			
EMERY MILLS*	OTTAUQUECHEE	3767	PAN UD	PRI-NON	EXIST	25	1.330	ROR			
DEWEYS MILL*	OTTAUQUECHEE	3768	PAN UD	PRI-UT	EXIST		2.740	ROR			
PIONEER STREET	WINOOSKI	3833	EAR UD				300				
HALIFAX							700				
NORTH MONTPELIER							400				
LADD DAM							143				
BARRETT							200				
BATCHELDER MILL							206				

Table 3-2

TYPES OF HYDRO PROJECTS IN NEW ENGLAND

DEVLOPER TYPE	NUMBER	PERCENT*
Private Utility	19	11
Private Nonutility	90	54
Public Utility	24	14
Public Nonutility	26	16
Hybrid	8	5
Unknown	27	
DAM TYPE		
Existing	133	82
New	30	18
Unknown	30	
HEAD		
Less than 25 feet	50	40
25 feet - 50 feet	39	31
51 feet - 100 feet	28	22
Greater than 100 feet	9	7
Unknown	69	
CAPACITY		
Less than 500 kW	50	27
500 kW - 5,000 kW	107	57
Greater Than 5,000 kW	29	16
Unknown	8	
OPERATING MODE		
Run-of-river	136	83
Peaking	24	15
Pumped storage	2	1
Tidal	1	1
Unknown	31	
DIVERSION LENGTH		
No diversion	27	20
1 foot - 300 feet	34	26
301 feet - 1,000 feet	32	24
Greater than 1,000 feet	39	30
Unknown	62	

*Percentages shown are based on the number of projects in each category for which data was available.

SECTION 4

CASE STUDIES

4.1 SELECTION OF CASE STUDY SITES

The selection of 15 sites for case study analysis was a joint effort of IECO, NERBC, and the Project Management Team. IECO compiled a list of 30 sites for further study and submitted it to NERBC. The sites recommended by IECO were based on the availability of necessary information and their suitability relative to the objectives of the study. Final selection of the 15 case study sites was based upon the requests of the Project Management Team, the availability of information, and the desire to have a reasonable number of sites representative of the various types of hydropower projects being actively investigated in New England. Selection of representative sites was performed using a statistical breakdown of the inventory. The sites were catalogued by feet of head, installed capacity, operating mode, diversion length, and developer type. Sites were selected from each of the six New England states.

4.2 ACQUISITION OF DATA

Following selection of the 15 case study sites, IECO engineers identified the information that would be needed to complete the analysis of each site. The NERBC Program Manager was then informed of the data gaps.

The developers of each site were contacted by telephone and a request for information was made. Some developers referred IECO to their engineering consultant; others required written requests. Each request was followed up at 3- to 7-day intervals, allowing time for mail delivery, etc. Some developers were difficult to contact and some were reluctant to cooperate, feeling that by providing information they were fostering competition for their site. These developers were assured that IECO had no further interest in their site, but in some cases their reluctance was insurmountable.

The NERBC Program Manager assisted in this effort by contacting the more reluctant developers. However, information concerning two sites could not be obtained within the time limits of the project. For this reason, 13 case studies were completed rather than 15.

When information could not be obtained from developers or from such official sources as FERC or DOE, other sources were used, such as U.S. Geological Survey (USGS) topographic maps and Federal Insurance Administration flood insurance studies. If a particular item of information could not be obtained from the sources listed above, engineering judgement was used to make reasonable assumptions. These assumptions were documented as the work proceeded.

4.3 FLOW REGIMES

With the endorsement of the Program Manager, three flow regimes were to be examined at each site: (1) no minimum flow release, (2) constant release of the 7Q10 flow at the base of the dam, and (3) constant release of the ABF at the base of the dam. The 7Q10 flow at each site was obtained from the USGS.

The FWS Aquatic Base Flow policy is, in essence, a site-specific policy in that a determination is made by FWS field offices as to whether spawning and incubation flow releases should be made during certain critical periods of the year in addition to maintenance of the median August flow year round. (See Appendix A for a full statement of the ABF policy.) If no fisheries resources critical to spawning and incubation exist at a site, spawning and incubation flow releases would not be required. In addition, periods for spawning and incubation are defined only as "fall/winter" and "spring" in the FWS statement of policy. These would be more narrowly defined by the field offices, depending on the stream segment involved (i.e., "spring" for one segment might mean April and May, while for another "spring" might be defined as May and June).

The scope of the study did not allow a determination to be made by IECO whether spawning and incubation flows would be required at a site, or how the length of a season over which they would be required would be defined. The time constraints of the study also precluded evaluation of the sites by USFWS to provide this information.

A decision was made, therefore, to consider each site with and without requirements for maintenance of spawning and incubation releases. This would provide a comparison of the effects of an upper and lower bound of ABF releases. The lower bound, called ABF-1, would be the smallest release likely to be recommended by FWS pursuant to the agency's flow recommendation policy, while the upper bound, called ABF-2, would be the largest release that could be recommended, if spawning and incubation releases were found to be necessary. The period for spawning was literally defined as extending from October through March and that for incubation as April through June.

The ABF flows were thus determined for each site in the following manner. The gaging station records were examined to determine the number of years of record and the extent of regulation and diversion. For sites with a minimum of 25 years of USGS gaging records and considered to be essentially free flowing, the ABF-1 release would be continuous throughout the year and equal to the median August flow. The ABF-2 releases would be equivalent to the historic median streamflow throughout the spawning and incubation periods as defined above.

For sites with less than 25 years of gaging records or for rivers regulated by dams or upstream diversions, the ABF-1 release would be constant throughout the year and equal to 0.5 cubic feet per second per square mile (cfsm) of drainage area. The ABF-2 release would be equal to 1.0 cfsm in

January, February, and March; 4.0 cfsm in April, May, and June; 0.5 cfsm in July, August, and September; and 1.0 cfsm, in October, November, and December.

For all cases, when the inflow immediately upstream of a project was less than the minimum flow release prescribed for that period, the release was set equal to the available inflow. The FWS would probably not recommend the ABF-2 flows as described herein; the spawning and incubation periods would be more narrowly defined by FWS.

Recreational flows for three sites were provided by the Program Manager and were also examined. One of the three sites was not studied due to a lack of sufficient information.

4.4 GENERATION STUDIES

Energy generation at a hydro site is dependent upon available flow and the corresponding head. Through the use of generation computer programs, IECO engineers estimated the average annual energy production at each case study site under each flow regime over a range of installed capacities.

The first step in performing the generation studies was to develop flow duration curves for each site. The USGS gaging station or stations closest to the project site were identified. The mean daily flows at each gage for the period of record were obtained directly from computer records maintained by the USGS. This flow data was used as input to an IECO program that computes the monthly and annual flow duration curves, mean monthly and annual flows for the period of record, the mean monthly flow for each month, and the mean annual flow for each calendar year and water year.

To relate the gaging station flows to the project site flows, the gaging station flow values were multiplied by a proration factor equal to the drainage area at the site divided by the drainage area at the gage. The monthly and annual flow duration curves are used as input to the energy generation program. These flow duration curves represent the hydrologic input into the generation program.

The next step in performing the generation studies was to develop the various site-specific curves, which represent the head available at the plant, including headwater, tailwater, and canal or penstock headloss curves.

Headwater rating curves were developed by performing hydraulic computations to determine the rise in pond elevation associated with increased streamflows. Several sites were found to be fitted with crest control gates. Since the plan of operation of the gates was not known, the pond level was assumed to remain constant.

Tailwater rating curves are a very critical element in determining the net head on a small hydro plant. The tailwater effects on a plant are often underestimated or ignored. IECO was able to obtain tailwater curves for several sites from the owner or their engineer. Flood insurance studies

obtained from the Federal Emergency Management Agency were used by an experienced hydraulic engineer to prepare tailwater curves for several other sites. The level of accuracy of these latter tailwater curves is acceptable for any appraisal study.

Where no tailwater data were available, a tailwater rating curve was estimated using tailwater curves from rivers of similar size and configuration and applying engineering judgement. The use of these tailwater curves is considered to be adequate for comparison purposes.

For those sites that have headrace canals, a headloss curve was computed. The headloss curve represents the head lost in the canal due to friction over a range of flows. The headloss increases with the flow. No attempt was made to optimize the flow by considering canal configuration or linings aimed at reducing headloss, as this was beyond the authorized scope of the project.

For those sites that have penstocks, penstock headloss curves were generated internally by an IECO computer program. Penstock diameters were selected for each installed capacity based on a headloss criterion. The selected penstock size was not allowed to cause unacceptable headloss at the rated flow of the turbine. Clearly, the greater the headloss in the penstock, the less energy generated. The penstock headloss curve is similar to the canal headloss curve in that it represents the head lost due to friction over a range of flows.

The selection of a minimum installed capacity to be analyzed for each site required a consistent approach. The minimum installed capacity for analysis for each site was selected by using the 90-percent exceedence flow on the annual flow duration curve as the minimum allowed flow to generate energy for the smallest turbine installed. This minimum flow, taken as 40 percent of turbine full-flow, was used with the power equation to determine the minimum installed capacity. A range of larger installed capacities was selected for energy generation studies for each site to provide sufficient data to plot an energy versus installed capacity curve for each flow release regime.

For sites with diversions, the postulated flow releases were made at the dam and not through the powerhouse. The use of a small turbine to generate electricity with the various required flow releases was considered at each site.

Energy generation estimates were made using the generation computer program mentioned previously. This program determines the flow; selects the associated headwater and tailwater elevations, the headlosses (if any); and the overall plant efficiency; and then computes the energy. This function is performed many times, yielding average monthly and annual energy generation values.

The use of small turbines to generate energy using the minimum flow releases was considered for the case study sites. The small turbines were usually fixed-blade, horizontal turbines. The fixed blades reduce the cost

of the units and limit the turbine to a specific operating flow. In the case of minimum flow releases, this constant flow feature is ideally suited to the release. Some of the units are actually pumps, which run in reverse, with minor design modifications allowing them to run efficiently as turbines. Adjustable blade turbines were also considered.

The fixed-blade units were considered for all installations smaller than 1,000 kW. Standardized, horizontal, tubular units with adjustable runner blades were considered for all installations larger than 100 kW. Then the most cost-effective unit was selected in the overlapping range between 100 kW and 1,000 kW. The adjustable-blade runner units are capable of handling a flow range of 40 to 105 percent of turbine full flow and, therefore, have wider application than the fixed-blade units.

The small turbines must be installed with the minimum of civil work. The quantity of energy that a small turbine generates is not sufficient to support a large concrete powerhouse or a penstock or tailrace excavation. One manufacturer of very small units (less than 50 kW) has reduced civil work to a minimum and the firm's sales representatives refer to the unit as a "turbine in a trash can." A major American manufacturer has recently introduced a line of mini-turbines (which are basically pumps run in reverse) and has installed a unit in a concrete caisson. The success of the operation has prompted the manufacturer to apply for a patent on the installation method. There are very many small hydro equipment manufacturers and each has a product with some particular advantage over the others.

4.5 COST ESTIMATES

Cost estimates were prepared for each case study site. A separate cost estimate was prepared for each installed capacity examined at each site. Sufficient information was available for nearly half the case study sites to enable preparation of a cost estimate suitable for a feasibility assessment of the project. This information consisted of detailed construction quantity estimates found in FERC files or supplied by the project sponsors or their engineers.

For several sites, quantity estimates were unavailable. However, suitable site descriptions or inspection reports were available which allowed an estimate of quantities to be made. When quantities could not be estimated, lump sum costs were estimated based upon the available data. The lump sum costs were estimated with the input of several highly experienced hydro engineers.

General construction costs were based on unit costs derived by the construction estimating professionals of Morrison-Knudsen Company, Inc., and through the use of cost curves, formulas, and data developed or updated by IECO engineers. All costs were escalated to reflect May 1981 dollars.

In most instances, turbine-generator prices were based upon quotations obtained for recent similar projects. In some cases, cost curves were used. Accessory electrical equipment, miscellaneous powerplant equipment, switchyard equipment, and transmission costs were based on cost curves.

An allowance for contingencies of 15 percent was applied to construction costs. The cost of engineering, administrative, and legal/financial services was estimated at 20 percent of construction costs plus contingencies. These allowances are typical of those used at the feasibility stage of a hydropower project. Interest and other financing costs were considered in the analysis, because they vary with the type of project sponsor, the financing method utilized, and changing market conditions.

4.6 OPTIMIZATION

Hydroelectric projects can be optimized using different approaches. Three common ones are:

- Maximize economic installed capacity. Capacity is added until the increase in the present worth of benefits is equal to the increase in the present worth of costs. At this point, investing an additional dollar in installed capacity would result in a return on investment that is exactly equal to the investment. A greater investment would result in a return that would be less than the additional amount invested.

- Maximize the internal rate of return. Install the capacity that would result in the largest possible internal rate of return. This is equivalent to installing the capacity with the lowest capital cost per kilowatt hour of energy produced annually, all other things being equal.

- Realize a specified internal rate of return or benefit-cost ratio. Capacity is added until the total IRR or CBR decreases to the minimum acceptable.

In this study, the second approach was used, as the optimum installed capacity could be selected without considering financing constraints or the value of power. The capital cost per megawatt hour of each proposed installation was determined by dividing the direct capital cost, computed as described in Section 4.5, by the average annual energy which would be generated by that particular installation, computed as described in Section 4.4. This procedure was repeated for a range of installed capacities for the various flow regimes at each site. The installation resulting in the lowest capital cost per megawatt-hour ($/MWh) was selected as the optimum installation for that site and flow regime.

4.7 ECONOMIC ANALYSES

Economic evaluations of the optimum project configuration for each selected site were made by comparing the anticipated benefits and costs over the lives of the projects. Three methods of analysis were considered:

- Internal rate of return (IRR). The discount rate at which the present worth of costs equals the present worth of benefits over the project life.

- Benefit-cost ratio (BCR). The ratio of present worth of benefits to the present worth of costs over the project life at a specified discount rate.

- Net present worth (NPW). The difference between the present worth of benefits and the present worth of costs over the project life at a specified discount rate.

Each of these types of analysis involves discounting the projected cash flow to account for the time value of money; however, significant differences exist in their application.

The IRR method is usually selected by private developers as the most appropriate method to evaluate hydro projects, as it gives them a measure of the return on their investment. This method can be rather misleading as to the effect of negative cash flow and the amount of capital actually required to sustain a project in the early years. Nonetheless, it is probably the best method for a developer to use, provided a side evaluation is made of the additional investments needed to make up the early deficits in cash flow.

The BCR method is frequently used to evaluate public projects. The whole philosophy of public projects is to formulate them so that their benefits exceed their costs over the expected life of the project. The biggest difficulty with this method is selecting an appropriate discount rate for use in the analysis.

The NPW method is also commonly used to compare the projected benefits and costs of projects, both public and private. However, this method can be quite misleading because it reports only the absolute difference between costs and benefits without relating it to project costs. For example, a project with a net present worth of one million dollars could cost two million or two hundred million dollars. Thus, we prefer to use the benefit-cost ratio or internal rate of return for analysis purposes, rather than net present worth.

Developers can also use the BCR method to evaluate projects. If the discount rate used to determine the present worth of the costs and benefits is that minimum rate of return acceptable to the developer, then a project with a benefit-cost ratio greater than 1.0 would be attractive to the developer.

Economic evaluations for hydroelectric projects are usually made by looking at the discounted cash flow over the life of the project based on some assumed interest rate and terms of financing. However, prediction of future interest rates is difficult in a market that is undergoing the

radical fluctuations currently being experienced. In addition, this procedure violates one of the principal rules of financial analysis; namely, that financing and investment decisions should not be mixed. By combining the two, an excellent project can be made to look unacceptable by bad financing or a bad project made to look good by excellent financing. To separate financing from economics in this analysis, the economic evaluation was made by treating the capital cost of the project as a one-time expenditure that occurs when the project comes on line, rather than using debt service as an annual cost. The financial aspects of the project were then evaluated by considering cash flow — particularly, the number of years of negative cash flow.

The economic evaluation of projects for this study was made using the IRR method for private developers and the BCR method for public entities. The following procedure was used:

- Annual operating costs were determined by adding operation and maintenance, general and administration, insurance, taxes, and contributions to a sinking fund for renewals and replacements, and then subtracting depreciation. Capital expenditures and tax credits were treated as one-time annual costs.

- Annual benefits for each year were computed by multiplying average annual energy production by the anticipated sale rate in mills per kWh.

- The present worths of costs and benefits were calculated by discounting the annual amounts to present values.

- The benefit-cost ratio was calculated by dividing the cumulative present worth of benefits by the cumulative present worth of costs.

- The internal rate of return was determined by repeating the calculation at various discount rates until the benefit-cost ratio was equal to one.

Economic evaluations of each of the sites were prepared from two perspectives — a tax-exempt entity, such as a municipality or a municipally-owned utility, and a private entity, such as a developer or an investor-owned utility.

Subsections 4.7.1 through 4.7.6 discuss in more detail the economic criteria and parameters used in the economic analyses.

4.7.1 Project Life

The proposed project developments were analyzed on the basis of a 20-year economic life. Most utilities value small hydro projects solely for their ability to replace oil-fired energy. While they recognize the projects

have a useful life in excess of 20 years, they expect other, cheaper alternatives to oil-fired energy to be available within 20 years. The actual life of the project's civil features, such as the dam and powerhouse, is often in excess of 50 years. The turbine-generator equipment will probably require refurbishing after about 30 years, to keep the operation and maintenance costs from becoming prohibitive. Significant repairs and replacements of transmission and switchgear equipment and other miscellaneous mechanical and electrical equipment will be required after 20 to 30 years. A renewals and replacements fund was provided to cover the cost of these replacements.

4.7.2 Interest During Construction

For the purpose of this study, it was assumed that the permanent financing would be put into place at the end of construction. Interest during construction was calculated using a typical cash drawdown assuming a 2-year construction schedule and calculating the interest between the date of the expenditure and project completion. The interest during construction was assumed to be 12 percent for public entities and 17 percent for private entities.

4.7.3 Escalation

Future escalation of construction and equipment costs and the value of capacity and energy is difficult to predict. For the purpose of this study, the project was assumed to be completed in 1981, thus placing the 1981 cost estimates in the same time frame as the 1981 power rates. An average inflation rate of 8 percent per year is recommended in escalating these project costs to any future year. This rate will tend to somewhat over-escalate the costs of turbine-generator equipment, because equipment vendors tend to escalate their prices prior to giving a preliminary price quotation. This tendency is offset by the fact that general construction costs have escalated at a rate greater than 8 percent during the last few years.

4.7.4 Annual Project Costs

The annual operating costs of a hydroelectric project can be divided into four categories: fixed costs, variable costs, income taxes, and depreciation. The fixed costs consist of the total capital expenditure required to build the project, less tax credits. Variable costs, which tend to increase at the general inflation rate, include operation and maintenence, renewals and replacements, administration, license fees. insurance, and property taxes. Income taxes includes state and federal income taxes. Depreciation is the deduction allowed for exhaustion, wear and tear, and obsolescence of a business's tangible assets. Each of the annual costs have the following detailed descriptions:

- Fixed Costs. The total capital cost of the project (direct construction cost plus interest during construction) was charged against the project as a one-time expenditure in the year in which the project

comes on line. Equity contributions and one-time credits were estimated for the typical private developer. Equity was assumed to be 20 percent of the total capital cost of the project, while the Investment Tax Credit of 10 percent and the Energy Tax Credit of 11 percent were assumed to apply to 85 percent and 90 percent, respectively, of a typical hydroelectric project's capital costs. These credits were assumed to be usable by the owner the year they occurred. The tax credits were used to reduce the cost of the project rather than treated as a benefit.

- Variable Annual Costs. Variable annual costs include operation and maintenance, general and administration, insurance, property taxes, and a sinking fund for renewals and replacements. These costs, except for property taxes, are estimated to be 2 percent of the total capital cost of the project in the first year. Property taxes were assumed to be 1.5 percent of the capital costs. These annual costs are subject to escalation for the life of the project.

- Income Taxes. Annual income taxes for the private entities are based on the gross revenues minus the variable annual costs, interest on the loan, and depreciation. For the purpose of this analysis, a 50-percent tax bracket was assumed.

- Depreciation. For simplicity, depreciable costs were assumed to be 90 percent of the direct construction cost. Land and land preparation costs are, in general, not subject to depreciation. Such nondepreciable costs are estimated to make up 10 percent of the cost of a typical hydroelectric project. Forty-year, straight-line depreciation was used. (Depreciation was not applied to the construction costs incurred by municipalities or municipally owned utilities, as they are not subject to income taxes.)

4.7.5 Annual Benefits

Annual benefits were assumed to be derived solely from the sale of energy. The amount of energy generated in the average year using the various flow regimes was considered to be available for sale and to have a buyer.

The value of power depends on the purchaser, the terms of the sale, and both state and federal regulations. The Public Utility Regulatory Policies Act (PURPA) of 1978 empowered FERC to prescribe rules requiring utilities to purchase power from and sell power to small power producers at "just and reasonable" rates. PURPA rules were required to be implemented by each state by March 1981. While some New England states have published final rules, others are still in the process of approving final rules. The implementation of these rules and their application to specific utilities

has not been completed in any New England state, although New Hampshire has well defined rules for projects under 5 MW and Connecticut and Rhode Island have final rules, but are still in the process of defining rates for a few remaining utilities. As of May 1, 1981, Massachusetts, Maine, and Vermont had not yet issued final rules.

Based on the available information, 1981 PURPA rates for the various New England states are estimated to be as follows:

State	Rate (mills/kWh)
Connecticut	56 nonfirm 71 firm
Massachusetts	70 to 80
Maine	70
New Hampshire	77 energy 82 reliable energy
Rhode Island	70 to 85
Vermont	66 off peak 90 peak 78 average

For the private developer, the revenues expected from the sale of power under the PURPA regulations is, in general, insufficient to secure the long-term financing of a hydroelectric project. Lenders usually require a long-term power sales contract or the pledge of other assets to secure the loan.

Many utilities in New England are responding to this need by signing contracts to puchase power based on a percentage of their avoided costs. This percentage is typically 90 percent, although some utilities will pay the full avoided cost. Thus, the market value of power today in New England ranges from 50 to 90 mills/kWh. This initial value of energy was considered in the analysis.

4.7.6 Inflation

The future rate of inflation is difficult to predict. For the purpose of this study, the general level of prices was assumed to escalate at an average rate of 8 percent per year for the life of the project. Energy was assumed to escalate at 11 percent per year for the next ten years, and 8 percent per year thereafter.

The rate of inflation used in the analysis significantly impacts the results of the analysis. One could argue that a more conservative, perhaps

more realistic, approach would be to reduce the anticipated rate of inflation to zero or some other small percentage after ten years. This approach, however, would not be consistent with the interest rates used in the financial evaluation. In other words, the high interest rates borrowers are forced to pay today are significantly impacted by anticipated future inflation. Should inflation actually be reduced significantly in the future, the borrower should be able to refinance at a lower rate, thereby reducing his annual costs.

4.8 FINANCIAL ANALYSIS

Cash flow statements were prepared for various combinations of interest rates, inflation rates, and energy values for typical private and public developers. The annual cash flow is determined by subtracting the annual costs from the annual benefits. When the annual costs of a project exceed the annual benefits, a condition called negative cash flow exists; and additional capital will have to be raised to make up revenue shortfalls.

Most developers — both private and public — place limits on the number of years of negative cash flow they will tolerate. A typical range is 0 to 5 years.

The following procedure was used to calculate the annual costs and benefits:

- The annual operating costs were determined by adding the debt service, operation and maintenance, general and administration, insurance, and taxes, and subtracting depreciation and tax credits.

- The annual benefits for each year were computed by multiplying the average annual energy production by the anticipated sale rate in mills per kWh.

- The annual cash flow was calculated by subtracting the annual costs from the annual benefits.

The annual debt service represents the levelized cost of repaying the principal and interest of the borrowed capital. For the example of a public entity financing the project, it was assumed they would finance 100% of the project costs, including interest during construction. Requirements for sinking funds normally associated with such financings were ignored, as their costs tend to be more than offset by the interest they generate. For the private developer, it was assumed that 20 percent of the total project costs would be provided as an equity investment and the remaining 80 percent would be financed with a conventional long-term loan.

Interest rates and term of loans selected for the example calculations were as follows:

Financing Entity	Equity	Term of Loan	Interest Rate
Public	0	30 years	10%
Private	20%	20 years	15%

The criteria used to predict the other annual costs and benefits are discussed in subsection 4.7.2 through 4.7.6.

4.9 SUMMARY OF ECONOMIC AND FINANCIAL STUDIES

Using the criteria and methods discussed in the previous subsections, graphs were developed which identify the minimum initial value of energy which will meet the economic and financial criteria of a typical public or private developer. See Figures 4-1 and 4-2. Projects plotting above the line exceed the minimum criteria. The curves can be used as follows:

- If the value of energy and the cost-energy ratio are both known, the point can be plotted to determine if the project formulation meets the minimum criteria. The project exceeds the minimum criteria of lines shown below it on Figures 4-1 and 4-2. For example, a cost-energy ratio of $600/MWh and energy value of 70 mills would be acceptable to a public entity (but not to a private developer), provided it could endure between 3 and 5 years of negative cash flow and provided it could finance the project in accordance with the specified criteria.

- If only the cost-energy ratio is known, the chart can be used to determine the initial cost of service and the minimum acceptable energy rate. This is done by entering the graph from the bottom using the cost-energy ratio and moving up until reaching the desired criteria line. Once the proper curve is reached, the energy value can be read off the vertical axis. For example, using a cost-energy ratio of $400/MWh, the following mill rates are determined from Figures 4-1 and 4-2:

Public Entity	
10% Discount Rate	34 Mills
15% Discount Rate	45 Mills
No Negative Cash Flow	62 Mills
Private Entity	
10% IRR	56 Mills
15% IRR	75 Mills
No Negative Cash Flow	68 Mills

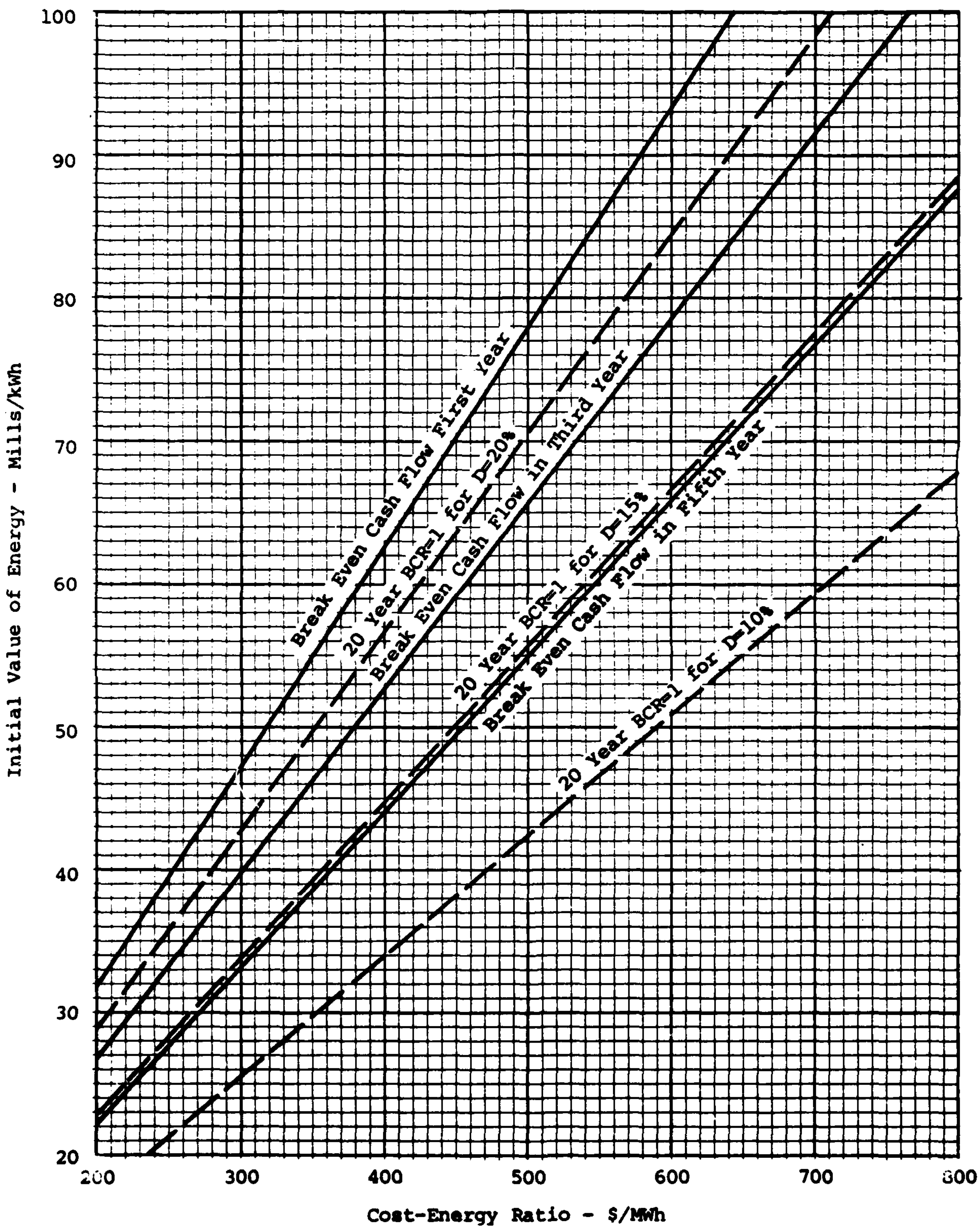


Figure 4-1. Tax Exempt Entity - Minimum Initial Value of Energy Required to Achieve Designated Financial or Economic Criteria.

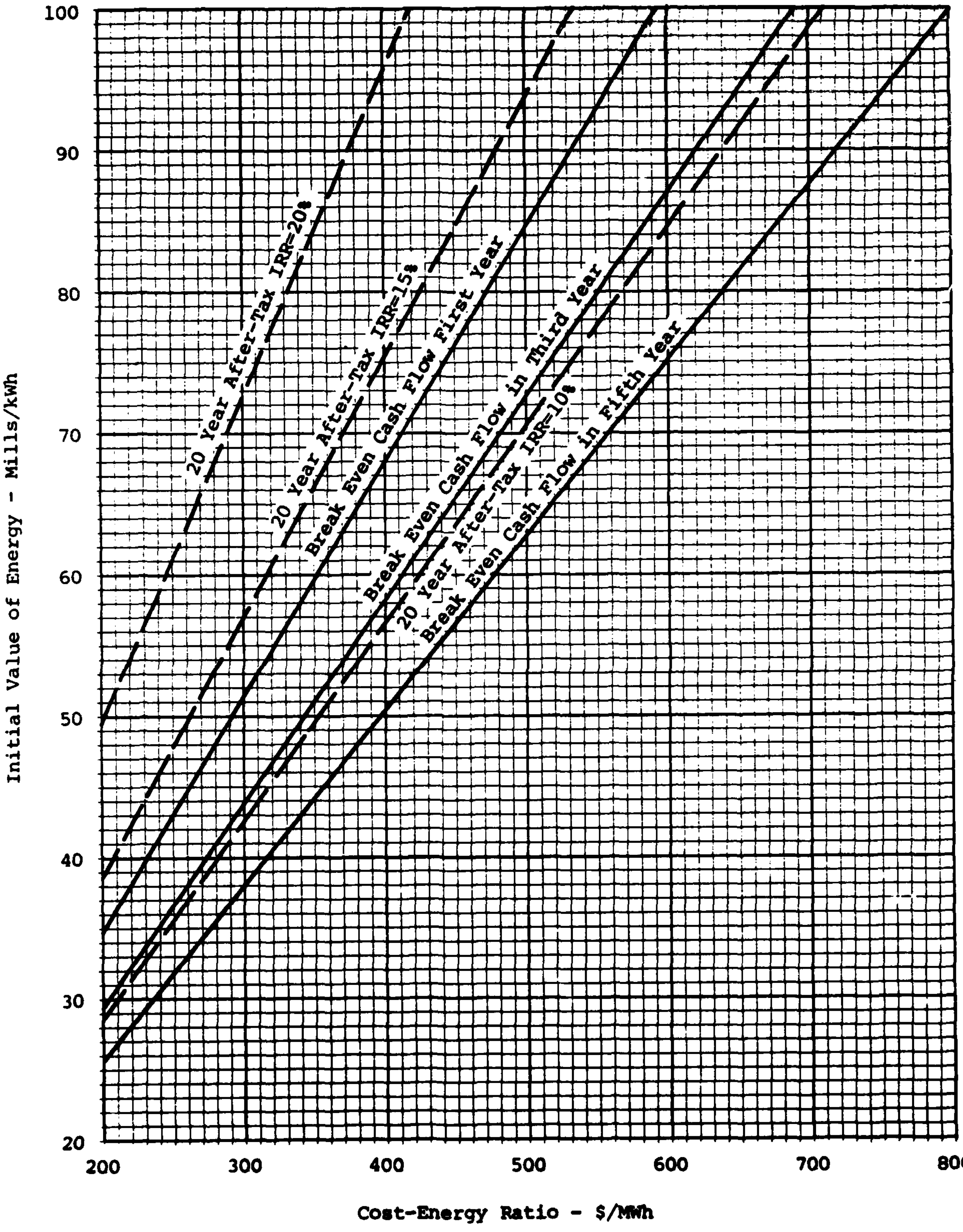


Figure 4-2. Taxable Entity - Minimum Initial Value of Energy Required to Achieve Designated Financial or Economic Criteria.

- If only the value of energy is known, the chart can be used to identify the maximum cost-energy ratio by entering the graph on the vertical axis at the known value of energy, and moving across the graph until intersecting the desired criteria line. The maximum cost-energy ratio can be read off the horizontal axis. For example, a private developer wishes to formulate a project with no negative cash flow. The local value of energy is 70 mills/kWh. Entering Figure 4-2 from the vertical axis at 70 mills/kWh and using the "break even cash flow first year" criteria line, the maximum cost-energy ratio is $420/MWh.

The maximum cost-energy ratio acceptable to a developer is dependent on the initial value of energy, as well his economic and financial criteria. For a private developer whose criteria relates to years of negative cash flow, these values are as follows:

MAXIMUM ACCEPTABLE COST-ENERGY RATIO FOR PRIVATE ENTITY

Initial Energy Value	Financial Criteria: Break Even 1st Year	Break Even 3rd Year	Break Even 5th Year
50 Mills	300 $/MWh	340 $/MWh	400 $/MWh
70	420	480	560
90	540	620	720

For a public entity, which may base its criteria on either cash flow or benefit-cost ratio, the maximum acceptable cost-energy ratios are as follows:

MAXIMUM ACCEPTABLE COST-ENERGY RATIO FOR PUBLIC ENTITY

Initial Energy Value	Financial Criteria: Break Even 3rd Year	Break Even 5th Year	BCR = 1 (Discount Rate = 10%)
50 Mills	380 $/MWh	450 $/MWh	590 $/MWh
70	540	630	840
90	690	820	1,070

The financial criteria selected to evaluate the cost impact of the various minimum flow release policies on hydroelectric feasibility was "break even" cash flow in 3 years for private developers and break even cash flow in 5 years for a public developer. The criteria are shown on Figure 4-3.

4.10 DESCRIPTIONS AND FINDINGS OF CASE STUDY SITES

Fifteen hydro projects were selected for case study analysis as discussed earlier. This subsection describes the 13 sites for which the case study analysis could be completed. A graphic display is presented for each

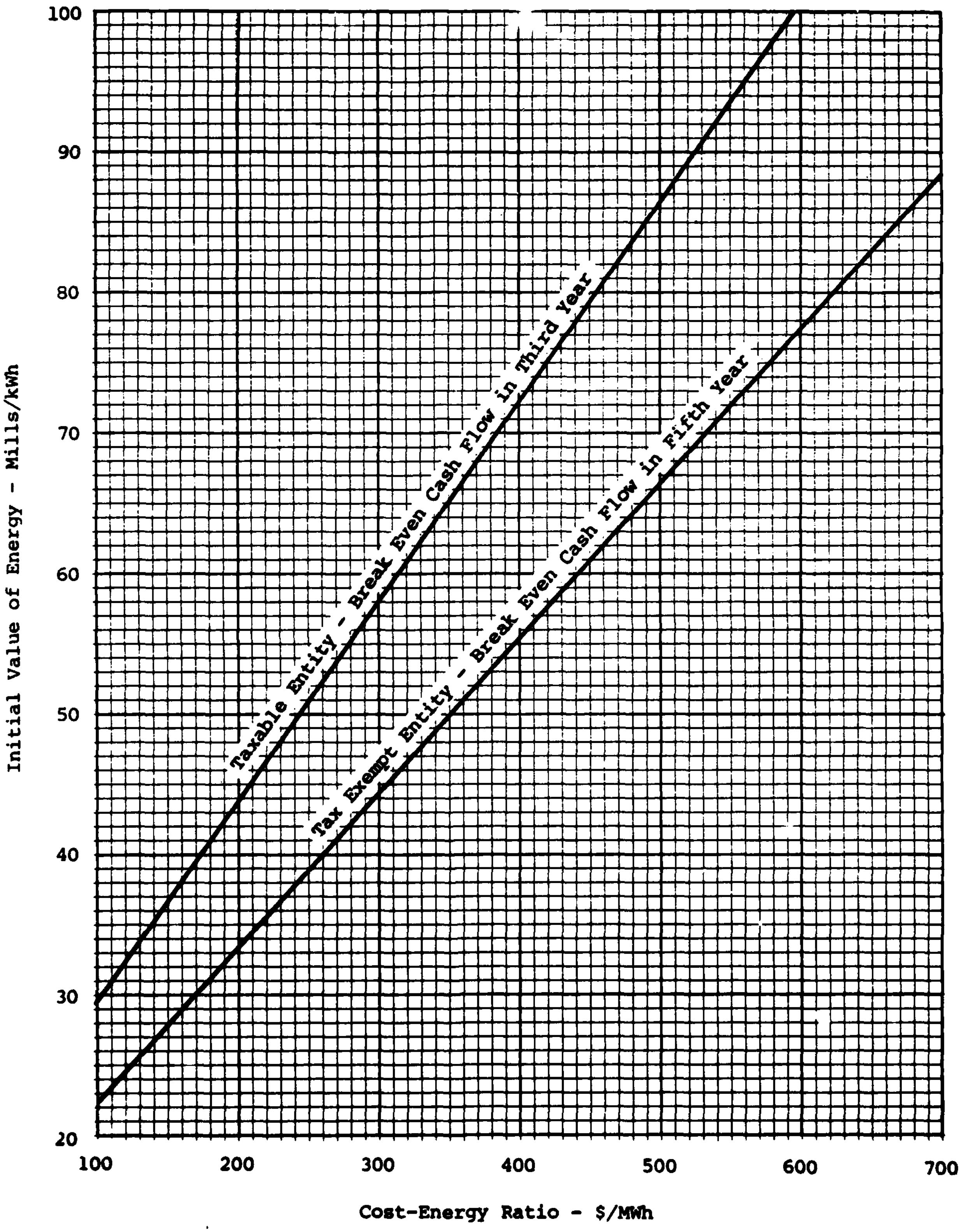


Figure 4-3. Criteria Used to Evaluate the Financial Impact the Various Flow Regimes Have on the Case Study Sites.

site. The graphics show all curves; a site plan; and energy, cost, and optimization information; and economic evaluation. Written descriptions are held to a minimum as all pertinent information is portrayed in the graphics.

4.10.1 Site A

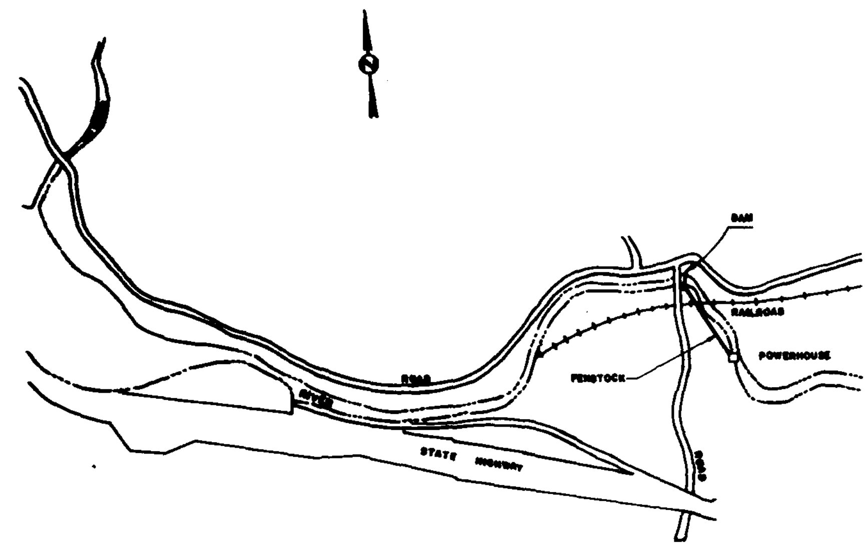
This run-of-river project is located at the site of a breached dam. Construction of a concrete overflow dam is proposed. An intake structure would be built at the dam to divert water into a steel penstock. The penstock would deliver water to the turbine in a powerhouse located 750 feet downstream. Twelve feet of head are available at the dam. The penstock increases the available head to 44 feet. Figure 4-4 shows a site plan and other pertinent information. Installed capacities ranging from 110 kW to 2,000 kW were investigated. The river is essentially free-flowing, with a 7Q10 flow of 5 cfs and a median August flow (ABF-1) equal to 51 cfs. The period of record extends over more than 38 years. The tailwater curve was estimated using a flood insurance study of the river. The headwater curve was constructed by performing hydraulic computations for a typical concrete overflow dam cross section.

The optimum installed capacity was found to be 1,000 kW. The energy generation curves on Figure 4-4 represent the average annual energy versus installed capacity associated with each of the various flow regimes. The installation of a small turbine at the foot of the dam to utilize the 7Q10 flow (5 cfs) would not be practical since the flow and head could only drive a 5-kW turbine-generator capable of generating 33 MWh per year at a capital cost of $180,000, resulting in a capital cost per MWh of $5,455. The median August flow (51 cfs) would be capable of driving a 40-kW propeller turbine; however, the flow is not always available, reducing the output of the unit substantially. The largest unit that could run continuously would be a 15-kW propeller unit capable of generating 122 MWh per year. The capital cost of the installation would be $168,000, reflecting a capital cost per MWh of $1,377.

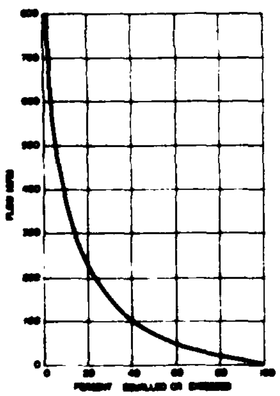
4.10.2 Site B

This run-of-river project is located at an existing dam, which is in good condition. A penstock along the left bank of the river runs from the dam to an existing powerhouse, creating a diversion of about 720 feet. Sixteen feet of head are available at the foot of the dam. The penstock increases the available head to 24 feet. Figure 4-5 presents the relevant information concerning this project. Installed capacities ranging from 1,000 kW to 3,000 kW were investigated. The river is regulated with several diversions upstream of the site. The 7Q10 flow at the site is 128 cfs; and with a drainage area of 714 square miles, 0.5 cfsm is equal to 357 cfs. The period of record at the nearest USGS gaging station is over 50 years. Tailwater, headwater, and headloss curves were obtained from a feasibility study prepared by a consulting engineering firm for the project owner.

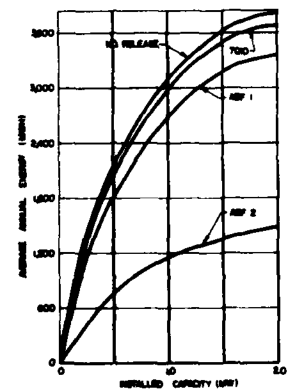
The optimum installed capacity was found to be 1,000 kW. Installation of a turbine at the dam to utilize the 7Q10 flow (128 cfs) was examined. The



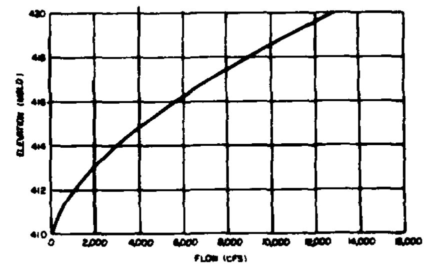
PLAN



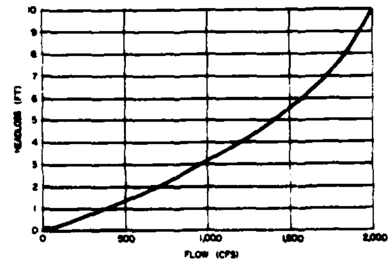
FLOW DURATION CURVE



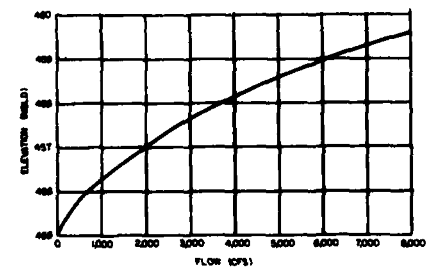
MAIN DEVELOPMENT ENERGY GENERATION CURVES



TAILWATER CURVE



PENSTOCK HEADLOSS CURVE



HEADWATER CURVE

NOTES - SITE A

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	110	400	1,000	2,000
CAPITAL COST	$3,495,000	$3,922,000	$4,880,000	$5,708,000
NO RELEASE	4,536	2,041	1,480	1,546
7Q10	4,848	2,142	1,580	1,570
ABF - 1	5,989	2,427	1,718	1,750
ABF - 2	14,664	5,997	4,017	3,885

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	1,000	1,000	1,000	1,000
	SMALL	0	5	15	15
	TOTAL	1,000	1,005	1,015	1,015
COST	MAIN	$4,880,000	$4,880,000	$4,880,000	$4,880,000
	SMALL	0	$ 100,000	$ 100,000	$ 100,000
	TOTAL	$4,880,000	$4,980,000	$4,980,000	$4,980,000
AVERAGE ANNUAL ENERGY (MWH)	MAIN	3,101	2,981	2,682	1,150
	SMALL	0	35	132	122
	TOTAL	3,101	3,016	2,814	1,272
CAPITAL COST PER MEGAWATT HOUR	MAIN	$ 1,480	$ 1,580	$ 1,780	$ 4,017
	SMALL	0	$ 2,485	$ 1,377	$ 1,377
	TOTAL	$ 1,480	$ 1,589	$ 1,701	$ 3,784

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	165	170	185	425
	TOTAL		174	185	412
TAXABLE ENTITY	MAIN	315	324	348	380
	TOTAL		330	348	344

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

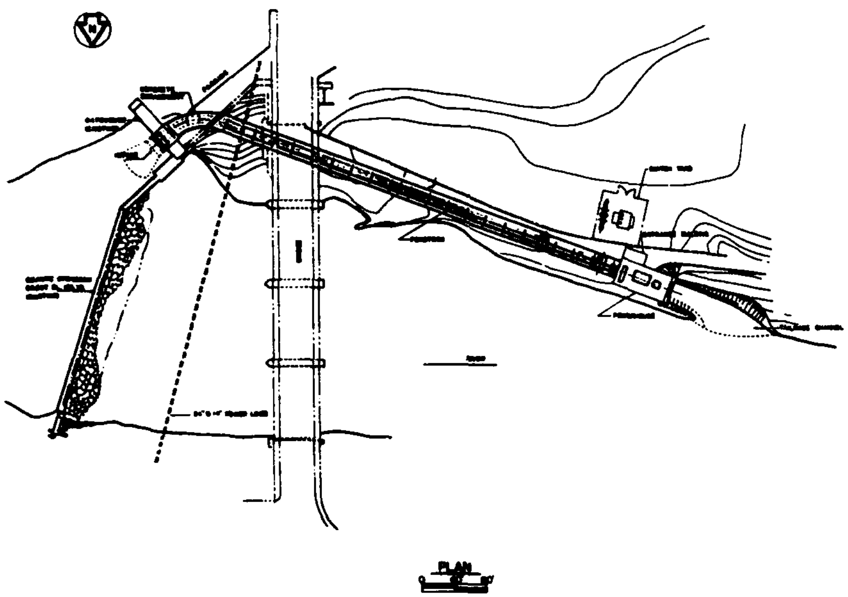
SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

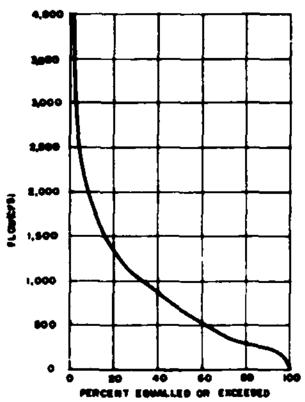
TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

NEW ENGLAND RIVER BASINS COMMISSION

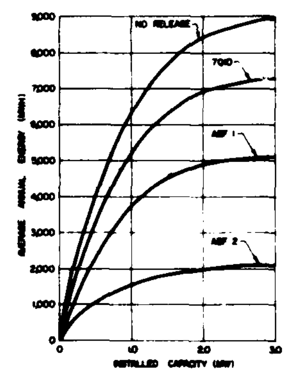
CASE STUDY SITE A

INTERNATIONAL ENGINEERING COMPANY, INC.

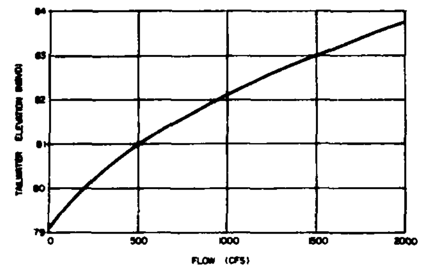




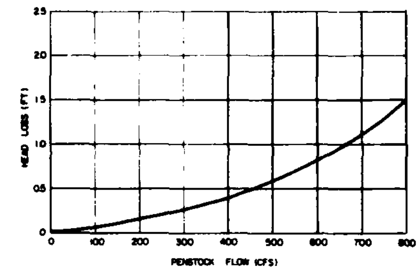
FLOW DURATION CURVE



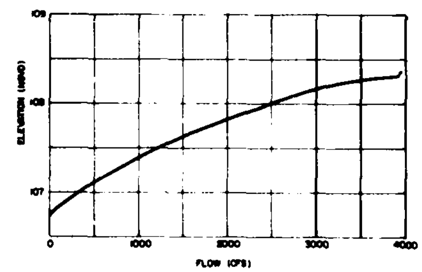
MAIN DEVELOPMENT
ENERGY GENERATION CURVES



TAILWATER CURVE



PENSTOCK HEADLOSS CURVE



HEADWATER CURVE

NOTES - SITE B

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	1,000	2,000	3,000	
CAPITAL COST	$2,346,000	$3,722,000	$4,[illegible],000	
NO RELEASE	373	441	[illegible]	
7Q10	494	[illegible]	[illegible]	
AGF - 1	631	[illegible]	[illegible]	
AGF - 2	1,475	[illegible]	2,315	

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	AGF - 1	AGF - 2
INSTALLED CAPACITY (KW)	MAIN	1,000	1,000	1,000	1,000
	SMALL	0	140	[illegible]	[illegible]
	TOTAL	1,000	1,140	[illegible]	[illegible]
COST	MAIN	$2,346,000	$2,346,000	$2,346,000	$2,346,000
	SMALL	0	$ 422,000	$ 751,000	$ 751,000
	TOTAL	$2,346,000	$2,767,000	$3,[illegible]	$3,[illegible]
AVERAGE ANNUAL ENERGY GAINS	MAIN	6,287	5,160	3,716	1,[illegible]
	SMALL	0	1,116	3,[illegible]	3,[illegible]
	TOTAL	6,287	6,276	7,[illegible]	4,[illegible]
CAPITAL COST PER MEGAWATT HOUR	MAIN	$ 373	$ 494	$ 631	$ 1,475
	SMALL	0	$ 378	$ [illegible]	$ [illegible]
	TOTAL	$ 373	$ 441	$ 442	$ [illegible]

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	AGF - 1	AGF - 2
TAX - EXEMPT ENTITY	MAIN	41	50	[illegible]	[illegible]
	TOTAL		46	46	70
TAXABLE ENTITY	MAIN	54	[illegible]	91	213
	TOTAL		64	64	[illegible]

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

NEW ENGLAND RIVER BASINS COMMISSION

CASE. STUDY SITE B

INTERNATIONAL ENGINEERING COMPANY, INC.

turbine selected was a 140-kW propeller unit capable of generating 1,116 MWh of energy each year. The capital cost per MWh would be $378 for this turbine. Use of the 0.5 cfsm ABF-1 flow (357 cfs) was also examined. This flow could drive a 390-kW propeller turbine located at the dam, generating approximately 3,285 MWh per year. This installation would cost approximately $751,000 resulting in a capital cost per MWH of $237.

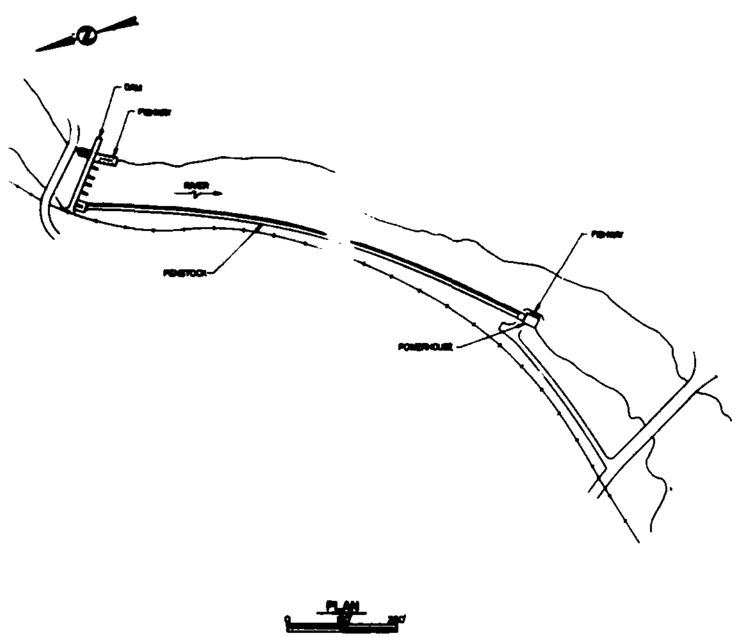
4.10.3 Site C

This run-of-river project is located at an existing dam that is in need of repair, although it is not breached. The dam would be repaired, as well as existing tainter gates, stanchion section, and penstock intake. The penstock would deliver water from the intake to the powerhouse located 1,200 feet downstream on the right bank. The penstock and the powerhouse would be of new construction. Twelve feet of head are available at the dam. The penstock increases the available head to 24 feet creating a diversion 1,200 feet long. Figure 4-6 presents the relevant project information. Installed capacities ranging from 300 kW to 3,000 kW were studied. The river is regulated and has a 7Q10 flow of 17 cfs. The drainage area of 280 square miles corresponds to a 0.5 cfsm flow of 140 cfs for ABF-1. The period of record at the nearest gaging station is more than 31 years. The tailwater curve was estimated from information supplied by the site developer. The headwater was assumed to be constant due to the crest control gates on the dam. The penstock headloss curve was computed based on flow.

The optimum installed capacity was found to be 1,000 kW. Installation of a turbine at the dam to utilize the 7Q10 flow was examined and found to be impractical due to the low flow (17 cfs) and head (12 feet), which could only drive a 14-kW propeller turbine, resulting in 114 MWh per year at a capital cost per MWh of $1,491. Use of the ABF-1 flow (140 cfs) was more practical, resulting in a potential installed capacity of 120 kW and average annual energy generation of 978 MWh. The capital cost per MWh of this small propeller turbine installation would be $380,000, or $389/MWh. The ABF-2 flows could support the same capacity.

4.10.4 Site D

This run-of-river site is located at an old industrial facility. The existing dam is in good condition and will require minimal repairs. An intake structure located to the left of the dam diverts water to a headrace canal, which delivers water to an existing powerhouse 2,170 feet downstream. The canal would require removal of silt and debris. The existing powerhouse would require rehabilitation. Six feet of head are available at the dam. The headrace canal increases the available head to 12 feet and creates a diversion more than 2,200 feet long. Figure 4-7 presents a site plan and other pertinent information. Installed capacities ranging from 250 kW to 1,000 kW were investigated. The river is highly regulated and has several upstream diversions. The 7Q10 flow is 66 cfs and the ABF-1 flow is 146 cfs. The period of record at the nearest gaging station is more than 38 years. The tailwater curve was estimated based on information supplied by the developer's engineer. The headwater curve was developed by performing hydraulic computations, as was the headloss curve.



PLAN

NOTES - SITE C

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	300	1,000	2,000	3,000
CAPITAL COST	$ 2,084,000	$ 3,337,000	$ 5,636,000	$ 7,866,000
NO RELEASE	929	567	701	887
7Q10	953	585	724	894
ABF - 1	1,192	741	921	1,100
ABF - 2	1,931	1,380	1,747	2,146

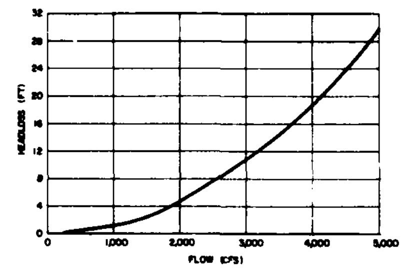
SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	1,000	1,000	1,000	1,000
	SMALL	0	14	120	180
	TOTAL	1,000	1,014	1,120	1,180
COST	MAIN	$3,337,000	$3,337,000	$3,337,000	$3,337,000
	SMALL	0	$ 170,000	$ 380,000	$ 380,000
	TOTAL	$3,337,000	$3,507,000	$3,717,000	$3,717,000
AVERAGE ANNUAL ENERGY (MWH)	MAIN	5,883	5,705	4,501	2,588
	SMALL	0	114	978	978
	TOTAL	5,883	5,819	5,479	3,566
CAPITAL COST PER MEGAWATT HOUR	MAIN	$ 567	$ 585	$ 741	$ 1,380
	SMALL	0	$1,491	$ 389	$ 389
	TOTAL	$ 567	$ 605	$ 678	$ 1,060

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	62	64	81	146
	TOTAL		66	74	116
TAXABLE ENTITY	MAIN	62	64	107	191
	TOTAL		67	95	163

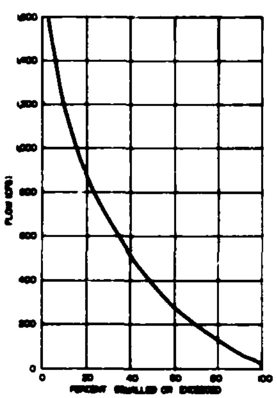
MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

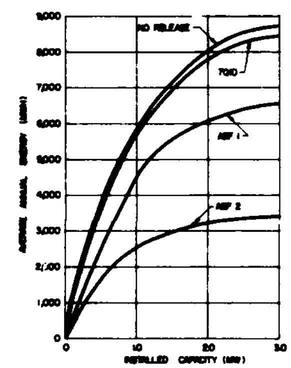
TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL



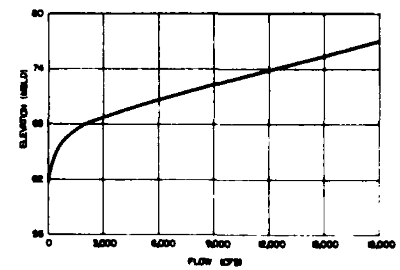
PENSTOCK HEADLOSS CURVE



FLOW DURATION CURVE



MAIN DEVELOPMENT ENERGY GENERATION CURVES

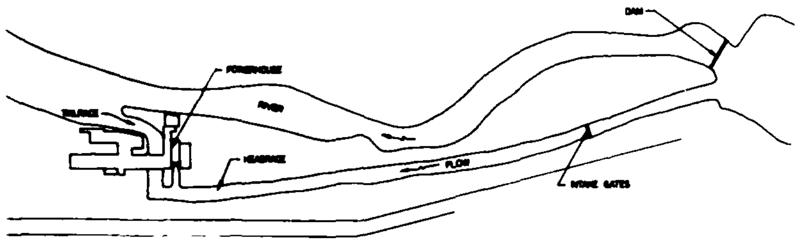


TAILWATER CURVE

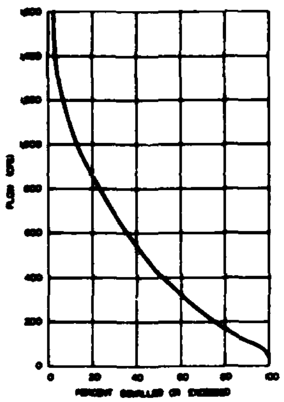
NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE C

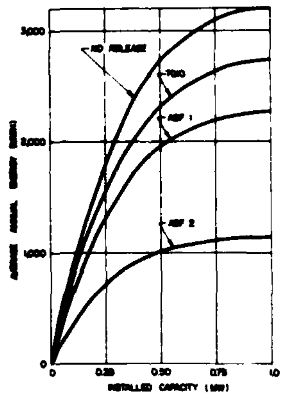
CONSULTING ENGINEERS
INTERNATIONAL ENGINEERING COMPANY, INC.
777 POST ROAD, DARIEN, CONNECTICUT 06820



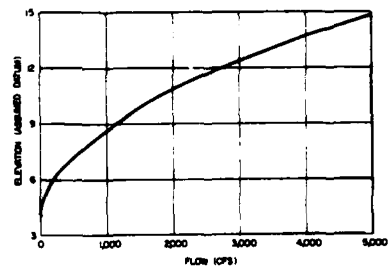
PLAN



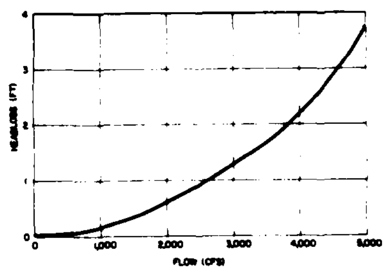
FLOW DURATION CURVE



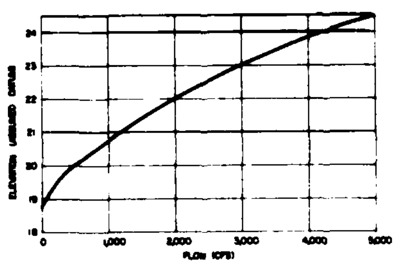
MAIN DEVELOPMENT
ENERGY GENERATION CURVES



TAILWATER CURVE



CANAL HEADLOSS CURVE



HEADWATER CURVE

NOTES - SITE D

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	250	500	750	1,000
CAPITAL COST	$ 858,000	$1,280,000	$2,162,000	$2,542,000
NO RELEASE	463	470	666	779
7Q10	563	551	616	916
ABF - 1	660	630	968	1,110
ABF - 2	1,220	1,270	1,580	2,200

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	500	500	500	500
	SMALL	0	25	50	50
	TOTAL	500	525	550	550
COST	MAIN	$1,280,000	$1,280,000	$1,280,000	$1,280,000
	SMALL	0	$ 275,000	$ 400,000	$ 400,000
	TOTAL	$1,280,000	$1,555,000	$1,680,000	$1,680,000
AVERAGE ANNUAL ENERGY (MWH)	MAIN	2,744	2,341	1,987	1,009
	SMALL	0	204	407	407
	TOTAL	2,744	2,545	2,394	1,416
CAPITAL COST PER MEGAWATT HOUR	MAIN	$ 470	$ 551	$ 666	$ 1,270
	SMALL	0	$1,348	$ 983	$ 983
	TOTAL	$ 470	$ 616	$ 716	$ 1,184

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	51	60	72	140
	TOTAL		67	76	151
TAXABLE ENTITY	MAIN	65	80	96	185
	TOTAL		89	103	172

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE D

INTERNATIONAL ENGINEERING COMPANY, INC.

The optimum installed capacity was found to be 500 kW. The 7Q10 flow could drive a 25-kW turbine at the dam, but would not be economically attractive with a capital cost per MWh of $1,348. The ABF-1 flow could drive a 50-kW turbine at the dam, but also would not be practical with a capital cost per MWh of $983. The ABF-2 flows could support the same size turbine. Adjustable blade turbines are not applicable at this site due to the very low head at the dam (6 feet).

4.10.5 Site E

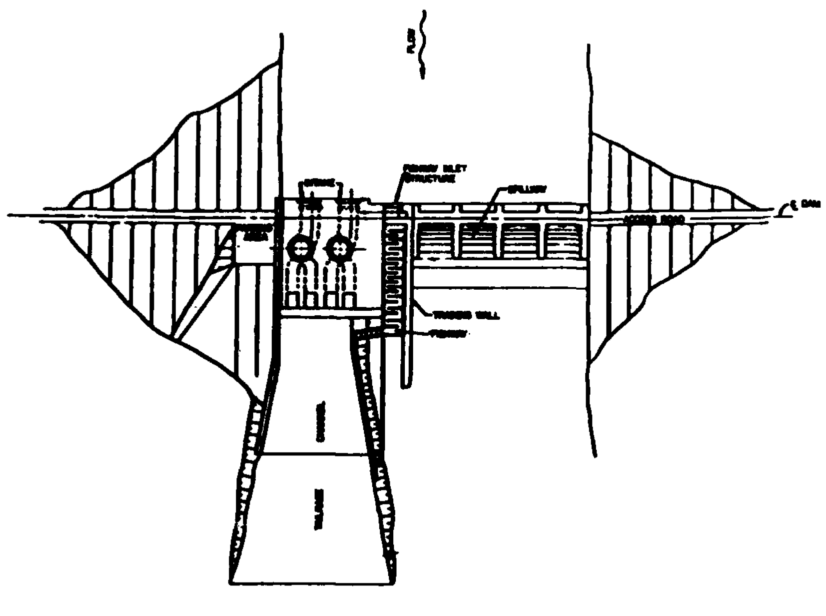
This project is a completely new development and will be operated as a peaking facility. No diversions are involved and minimum flow releases would be met when the plant is operating. Figure 4-8 presents a site plan and other pertinent information. Available head is equal to 38 feet. Installed capacities ranging from 8,000 kW to 20,000 kW were investigated. The river is regulated. The 7Q10 flow is 61 cfs and the ABF-1 flow is 579 cfs. The period of record for the nearest gaging station covers 44 years. The tailwater curve was estimated based on information in the preliminary permit application. The headwater was assumed to vary 4 feet during the operating period.

The optimum installed capacity was found to be 8,000 kW. Installation of a 125-kW propeller turbine to utilize the 7Q10 flow was investigated and found to have a capital cost per MWh of $397. Use of a 2,000-kW adjustable blade turbine to handle the ABF-1 flow (579 cfs) could produce 13,339 MWh per year and would cost approximately $2,600,000 to install, resulting in a capital cost per MWh of $198.

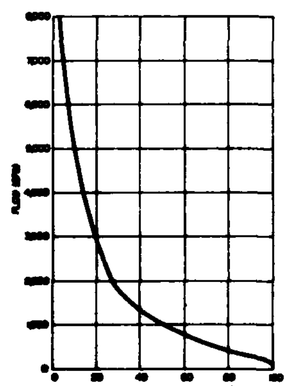
4.10.6 Site F

This run-of-river site is at an existing dam that will require minimal repairs. An intake structure at the left dam abutment diverts the flow into a 640-foot-long canal. The canal delivers water to an existing powerhouse creating a diversion nearly 700 feet long. Figure 4-9 presents a site plan and other pertinent information. The head available at the dam is equal to 10 feet. The canal increases the available head to 18 feet. Installed capacities ranging from 500 kW to 2,000 kW were investigated. The river is regulated and has several diversions upstream of the project site. The 7Q10 flow is 33 cfs and the ABF-1 flow is 177 cfs. The period of record for the nearest USGS gaging station is more than 15 years. The tailwater curve was developed using a flood insurance study of the river in the project area. The headwater curve was developed by performing hydraulic computations of flow over the dam. The canal headloss curve was also developed by hydraulic computations.

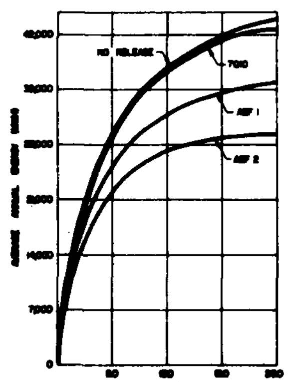
The optimum installed capacity was found to be 500 kW based on minimum capital cost per MWh. However, a 1,000-kW installation was nearly as cost-effective and would probably have a larger net return over the life of the project. For this reason, a 1,000-kW installation was selected. Installation of a small turbine at the dam to utilize the minimum flow releases was also considered. The 7Q10 flow of 33 cfs would be capable of driving a 15-kW propeller turbine nearly continuously. However, the capital cost per MWh of energy produced by such an installation would be



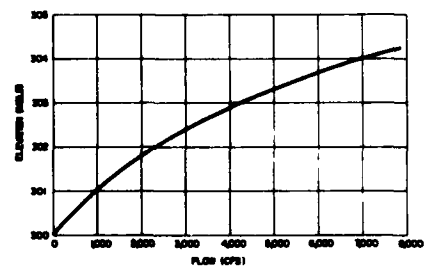
PLAN



FLOW DURATION CURVE



MAIN DEVELOPMENT ENERGY GENERATION CURVES



TAILWATER CURVE

NOTES - SITE E

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	8,000	12,000	16,000	20,000
CAPITAL COST	$17,714,000	[illegible]	[illegible]	[illegible]
NO RELEASE	501	531	[illegible]	[illegible]
7Q10	511	[illegible]	[illegible]	573
ABF - 1	[illegible]	642	[illegible]	[illegible]
ABF - 2	[illegible]	[illegible]	[illegible]	[illegible]

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	8,000	8,000	[illegible]	[illegible]
	SMALL	0	[illegible]	2,000	[illegible]
	TOTAL	8,000	[illegible]	[illegible]	[illegible]
COST	MAIN	$17,714,000	$17,714,000	$17,714,[illegible]	$17,714,[illegible]
	SMALL	0	$ [illegible]	$ [illegible]	$ [illegible]
	TOTAL	$17,714,000	[illegible]	[illegible]	[illegible]
AVERAGE ANNUAL ENERGY (MWH)	MAIN	35,340	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	35,340	[illegible]	[illegible]	[illegible]
CAPITAL COST PER MEGAWATT HOUR	MAIN	$ 501	$ 511	$ [illegible]	$ [illegible]
	SMALL	0	$ [illegible]	$ [illegible]	$ [illegible]
	TOTAL	$ 501	$ [illegible]	$ [illegible]	$ [illegible]

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	[illegible]	57	64	74
	TOTAL		[illegible]	51	57
TAXABLE ENTITY	MAIN	72	75	[illegible]	[illegible]
	TOTAL		73	[illegible]	79

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

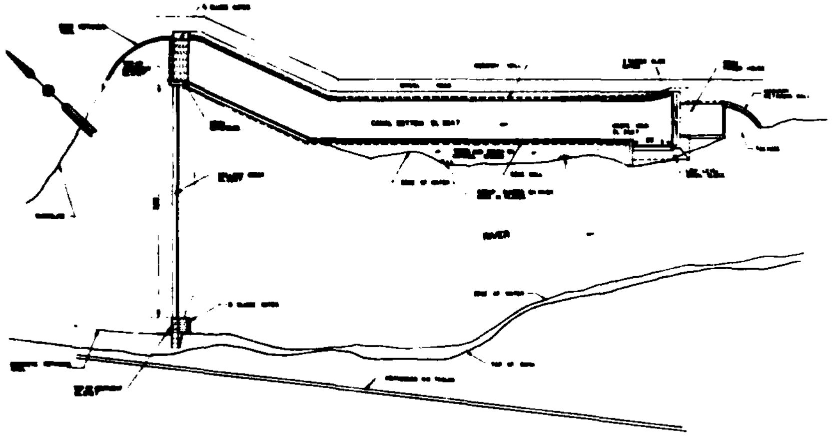
SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

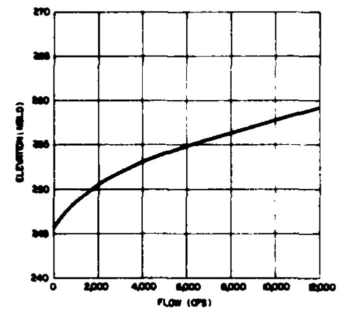
NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE E

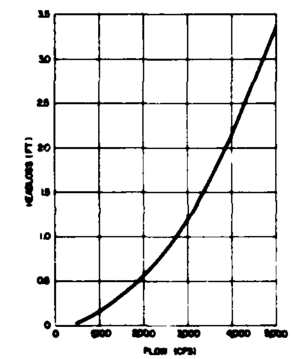
INTERNATIONAL ENGINEERING COMPANY, INC.



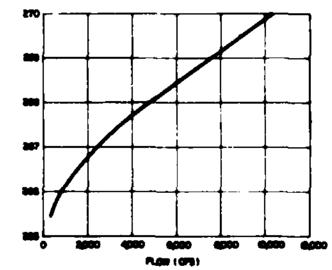
PLAN



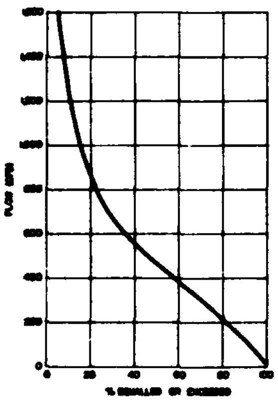
TAILWATER CURVE



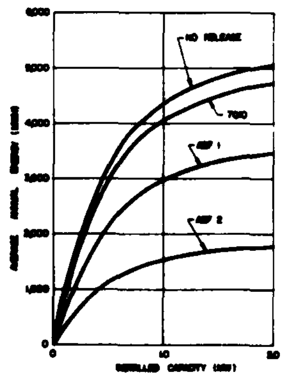
CANAL HEADLOSS CURVE



HEADWATER CURVE



FLOW DURATION CURVE



MAIN DEVELOPMENT
ENERGY GENERATION CURVES

NOTES - SITE F

CAPITAL COST PER [illegible] - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	800	1,000	[illegible]	2,000
CAPITAL COST	$1,216,000	$1,717,000	$2,[illegible]	$[illegible]
NO RELEASE	304	[illegible]	[illegible]	[illegible]
7Q10	410	424	[illegible]	[illegible]
ABF - 1	[illegible]	570	730	[illegible]
ABF - 2	1,085	1,121	1,404	1,[illegible]

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	800	800	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	800	[illegible]	[illegible]	[illegible]
COST	MAIN	$1,216,000	$1,[illegible]	$1,[illegible]	$1,[illegible]
	SMALL	0	$[illegible]	$[illegible]	$[illegible]
	TOTAL	$1,216,000	$1,[illegible]	$1,[illegible]	$1,[illegible]
AVERAGE ANNUAL ENERGY [illegible]	MAIN	3,[illegible]	2,[illegible]	2,[illegible]	1,[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	3,[illegible]	3,[illegible]	3,[illegible]	[illegible]
CAPITAL COST PER MEGAWATT HOUR	MAIN	$ 304	$ [illegible]	$ [illegible]	$ 1,[illegible]
	SMALL	0	[illegible]	$ [illegible]	$ [illegible]
	TOTAL	$ 304	$ 441	$ [illegible]	$ [illegible]

[illegible] VALUE OF ENERGY [illegible] TO [illegible] [illegible] ([illegible])					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	TOTAL		[illegible]	[illegible]	[illegible]
TAXABLE ENTITY	MAIN	57	[illegible]	[illegible]	[illegible]
	TOTAL		[illegible]	74	[illegible]

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE F

INTERNATIONAL ENGINEERING COMPANY, INC.

$1,000. The ABF-1 flow of 177 cfs would be capable of driving a 120-kW propeller turbine continuously and would have a capital cost per MWh of $395. The ABF-2 flow could also support a machine of similar size, but a larger 500-kW machine with adjustable blades could operate over a greater flow range and would have a capital cost per MWh of $320, with annual energy generation estimated at 2,200 MWh.

IECO was also asked to consider recreational flows of 800 cfs to be released year-round at the base of the dam. However, this was not considered realistic because average inflow to the dam exceeds 800 cfs during only 2 months of the year — March and April.

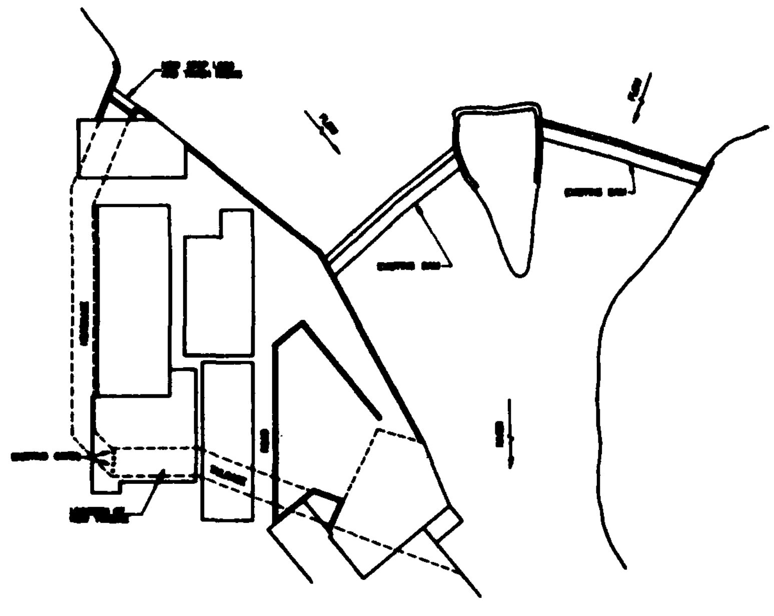
4.10.7 Site G

This run-of-river project is located at an industrial complex and utilizes an existing dam. An intake structure upstream of the dam on the right bank diverts water into an existing headrace canal. The dam, intake gates, and headrace canal will all require minimal repairs. The canal is about 220 feet long and delivers water to an existing powerhouse within the industrial complex. A 200-foot-long tailrace canal returns water to the river from the powerhouse. Water is diverted from a 240-foot-long reach of the river. A site plan and other pertinent information appear on Figure 4-10. Twelve feet of head are available at the dam and the diversion increases the head at the powerhouse to 23 feet. Installed capacities ranging from 80 kW to 500 kW were studied. The river is regulated and has several upstream diversions. The 7Q10 flow is 19 cfs and the ABF-1 flow (0.5 cfsm) is 35 cfs. The period of record for the nearest USGS gaging station is more than 38 years. The tailwater curve was estimated based on information supplied by the developer's engineer. The headwater and canal headloss curves were developed by performing hydraulic computations.

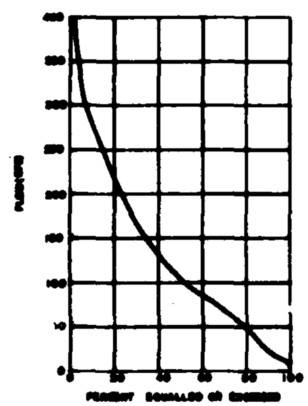
The optimum installed capacity was found to be 500 kW. Installation of a small turbine at the dam to utilize the minimum flow releases was also considered. The 7Q10 flow (19 cfs) would be capable of driving a 15-kW turbine continuously, generating 122 MWh per year at a capital cost per MWh of $1,200. The ABF-1 flow of 35 cfs could drive a 25-kW turbine nearly continuously, generating 204 MWh per year at a capital cost per MWh of $913. The ABF-2 flow would support the same installed capacity.

4.10.8 Site H

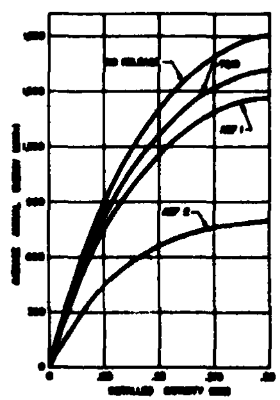
This run-of-river site is located at the site of a dam that was washed out many years ago. Construction of a concrete overflow dam outfitted with crest control gates is proposed. An intake structure would be built at the right dam abutment to divert water to a 4,020-foot-long canal. The canal is existing but would require clearing and cleaning. A new powerhouse would be built at the terminus of the canal. The total diversion length is about 4,700 feet. A site plan and other relevant information appear on Figure 4-11. Gross head at the dam is 19 feet. The headrace canal increases the available head to 30 feet. Installed capacities ranging from 500 to 3,000 kW were studied. The river is regulated upstream of the site. The 7Q10 flow is 48 cfs and the 0.5 cfsm flow is 195 cfs. The period of record for the nearest USGS gaging station is more than 63



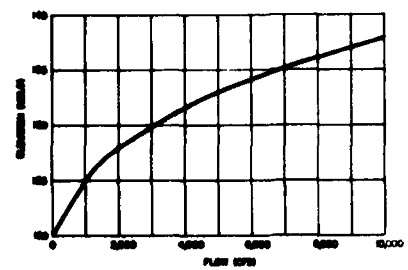
PLAN



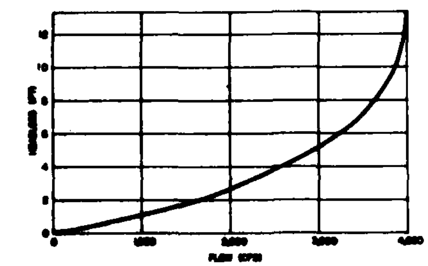
FLOW DURATION CURVE



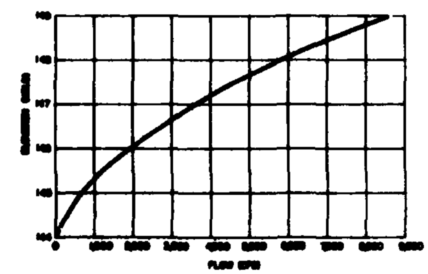
MAIN DEVELOPMENT ENERGY GENERATION CURVES



TAILWATER CURVE



CANAL HEADLOSS CURVE



HEADWATER CURVE

NOTES SITE 6

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	[illegible]	[illegible]	[illegible]	[illegible]
CAPITAL COST	[illegible]	[illegible]	[illegible]	[illegible]
NO RELEASE	[illegible]	[illegible]	[illegible]	[illegible]
7Q10	[illegible]	[illegible]	[illegible]	710
AGF - 1	[illegible]	[illegible]	[illegible]	[illegible]
AGF - 2	[illegible]	[illegible]	[illegible]	[illegible]

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	AGF - 1	AGF - 2
INSTALLED CAPACITY (KW)	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]
COST	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]
AVERAGE ANNUAL ENERGY (MWH)	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]
CAPITAL COST PER MEGAWATT HOUR	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]					
		NO RELEASE	7Q10	AGF - 1	AGF - 2
TAX - EXEMPT ENTITY	MAIN	70	70	[illegible]	[illegible]
	TOTAL		[illegible]	[illegible]	[illegible]
TAXABLE ENTITY	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	TOTAL		[illegible]	[illegible]	[illegible]

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

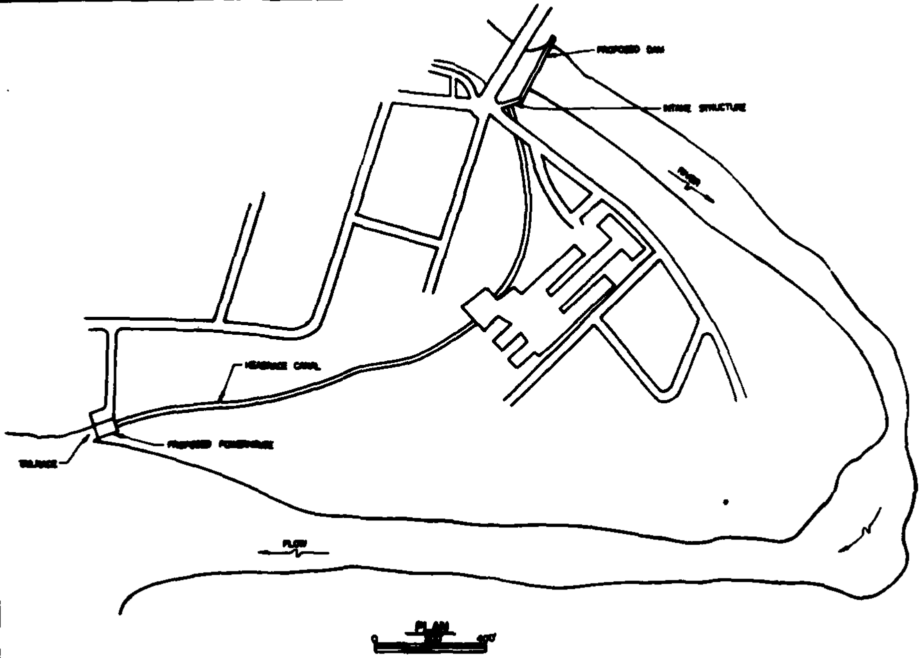
SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

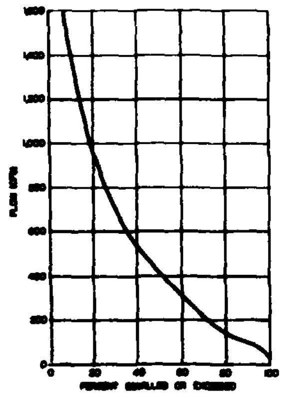
NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE 6

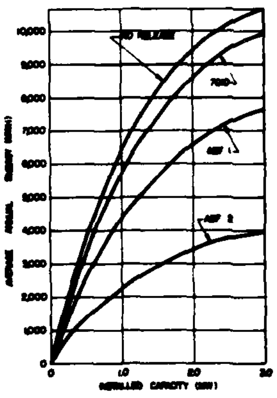
[illegible]



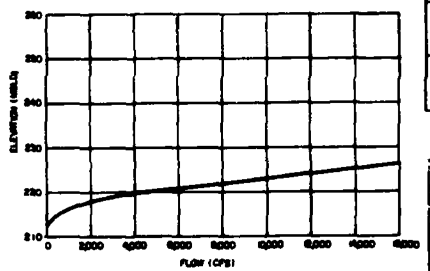
PLAN



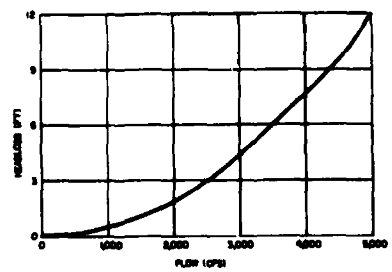
FLOW DURATION CURVE



MAIN DEVELOPMENT ENERGY GENERATION CURVES



TAILWATER CURVE



CANAL HEADLOSS CURVE

NOTES - SITE H

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	500	1,000	2,000	3,000
CAPITAL COST	$4,462,000	$4,897,000	$[illegible]	$6,460,000
NO RELEASE	1,176	755	601	590
7Q10	1,302	831	651	646
ABF - 1	1,749	1,100	855	857
ABF - 2	3,245	2,085	1,721	1,646

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	3,000	3,000	3,000	3,000
	SMALL	0	60	200	600
	TOTAL	3,000	3,060	3,200	3,600
COST	MAIN	$6,460,000	$6,460,000	$6,460,000	$6,460,000
	SMALL	0	$ 255,000	$ 814,000	$1,180,000
	TOTAL	$6,460,000	$6,715,000	$7,274,000	$[illegible]
AVERAGE ANNUAL ENERGY (MWH)	MAIN	10,940	10,011	7,716	3,927
	SMALL	0	473	1,629	3,559
	TOTAL	10,940	10,484	9,345	7,486
CAPITAL COST PER MEGAWATT HOUR	MAIN	$590	$646	$837	$1,645
	SMALL	0	$540	$500	$ 331
	TOTAL	$590	$641	$778	$1,025

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	66	71	92	180
	TOTAL		70	86	112
TAXABLE ENTITY	MAIN	86	95	121	230
	TOTAL		95	112	148

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE H

CONSULTING ENGINEERS

INTERNATIONAL ENGINEERING COMPANY, INC.

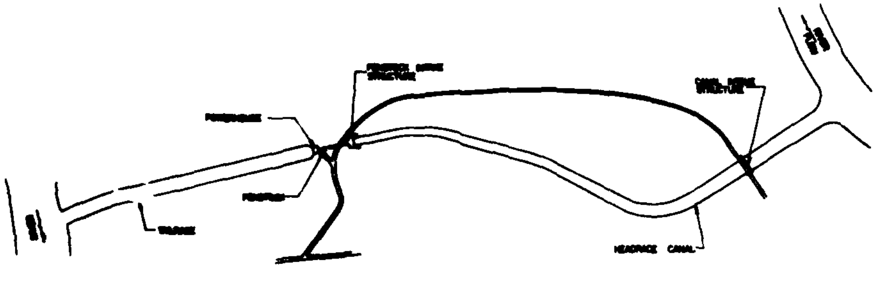
years. The tailwater curve for this site was developed by adjusting a tailwater curve for a site upstream supplied by the site developer. The headwater was assumed to remain constant due to the crest control gates on the proposed dam. The canal headloss curve was developed by performing hydraulic computations.

The optimum installed capacity was found to be 3,000 kW. Installation of a small turbine at the dam to utilize the minimum flow releases was also considered. The 7Q10 flow of 48 cfs could support a 60-kW propeller turbine operating continuously. The average annual energy generation would be 473 MWh and the capital cost of the small generating station would be $258,000 resulting is a capital cost per MWh of $545. The ABF-1 flow (195 cfs) would be capable of driving a 250-kW turbine; however, this flow is not always available. A 200-kW propeller turbine, which would operate nearly continuously at a flow of 155 cfs, would be more feasible. This unit would have a capital cost of $814,000 and would generate 1,629 MWh per year, resulting on a capital cost per MWh of $500. An adjustable-blade 600-kW turbine would be recommended for the ABF-2 flow, which would be capable of handling flows from 150 to 400 cfs. The installation would cost $1,600,000 and would be capable of generating 3,509 MWh per year resulting in a capital cost per MWh of $331.

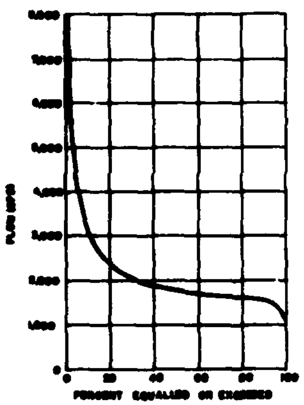
4.10.9 Site I

This run-of-river site is located at an existing breached dam, which the developer proposes to restore to its original design. An intake structure would be constructed on the left bank upstream of the dam and would divert water into a 4,200-foot-long headrace canal. The canal terminates at a penstock intake structure, which serves as the inlet to a 330-foot-long penstock. The penstock delivers water from the canal to the powerhouse. A tailrace canal approximately 2,100 feet long would return water to the river from the powerhouse. Water would be diverted from the river for a total of about 12,000 feet. A site plan and other pertinent information appear on Figure 4-12. Sixteen feet of head are available at the dam. The canal and penstock diversion increases the available head to 68 feet. Installed capacities ranging from 2,500 to 15,000 kW were considered. The river is highly regulated by upstream flood control structures. The 7Q10 flow at this site is 1,207 cfs and the 0.5 cfsm (ABF-1) flow is 622 cfs. This is the only case study site where the 7Q10 flow is greater than the ABF-1 flow. This is due to the regulation of the river. The period of record at the nearest USGS gaging station is more than 50 years. The tailwater curve for this site was estimated from information obtained from the FERC preliminary permit application. The headwater and canal headloss curves were developed by performing hydraulic computations. Penstock headloss curves were generated internally by the computer.

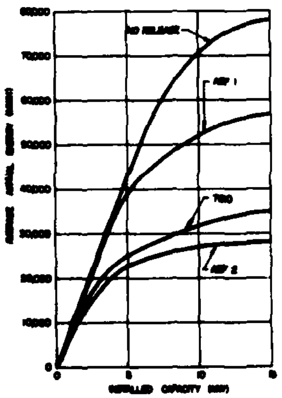
The optimum installed capacity was found to be 10,000 kW. Construction of a generating station at the dam to utilize the minimum flow releases was also considered. The 7Q10 flow (1,207 cfs) would be capable of driving a 1,300-kW turbine-generator continuously, generating an average annual energy output of 10,590 MWh. The total capital cost would be $1,786,000, resulting in a capital cost per MWh of $169. The ABF-1 flow of 622 cfs could drive a 675-kW turbine continuously, resulting in average annual



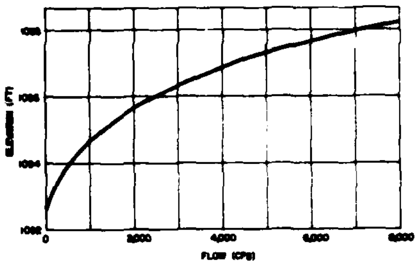
PLAN



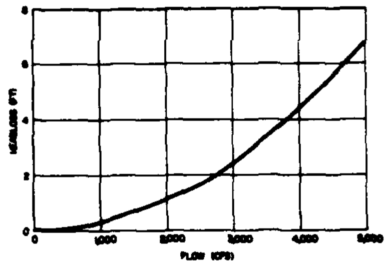
FLOW DURATION CURVE



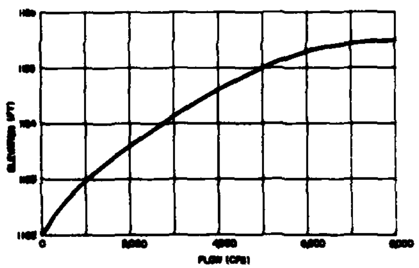
MAIN DEVELOPMENT ENERGY GENERATION CURVES



TAILWATER CURVE



CANAL HEADLOSS CURVE



HEADWATER CURVE

NOTES - SITE 1

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (MW)	2,800	[illegible]	[illegible]	[illegible]
CAPITAL COST	[illegible]	[illegible]	[illegible]	[illegible]
NO RELEASE	647	[illegible]	[illegible]	[illegible]
7Q10	[illegible]	[illegible]	572	[illegible]
ASF - 1	[illegible]	[illegible]	[illegible]	[illegible]
ASF - 2	1,005	[illegible]	[illegible]	[illegible]

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ASF - 1	ASF - 2
INSTALLED CAPACITY (MW)	MAIN	10,000	[illegible]	[illegible]	[illegible]
	SMALL	0	1,300	[illegible]	[illegible]
	TOTAL	10,000	11,300	[illegible]	[illegible]
COST	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]
AVERAGE ANNUAL ENERGY (MWH)	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]
CAPITAL COST PER MEGAWATT HOUR	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]

[illegible]					
		NO RELEASE	7Q10	ASF - 1	ASF - 2
TAX - EXEMPT ENTITY	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	TOTAL		[illegible]	[illegible]	[illegible]
TAXABLE ENTITY	MAIN	37	[illegible]	[illegible]	[illegible]
	TOTAL		[illegible]	[illegible]	[illegible]

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE 1

energy generation of 5,499 MWh. The capital cost for the installation would result in a capital cost per MWh of $213. The ABF-2 flows could support a similar size unit. A 1,800-kW turbine with adjustable blades could also be installed to handle ABF-2 flows ranging from 630 cfs to 1,575 cfs, resulting in an estimated average annual energy generation of 13,379 MWh. The capital cost of the installation would be $2,267,000, resulting in a capital cost per MWh of $169.

IECO was also asked to consider recreational flows of 1,200 to 1,500 cfs to be released at the base of the dam. The 7Q10 flow of 1,207 cfs falls within this range; therefore, the 7Q10 analysis will apply to the recreational flows also.

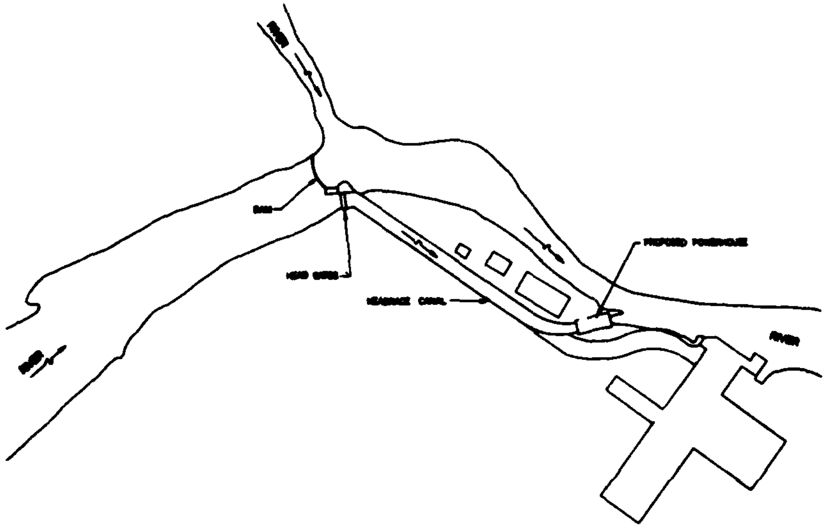
4.10.10 Site J

This run-of-river site is located at an existing dam, which is in good condition. An intake structure at the right dam abutment diverts flow into a 1,200-foot-long headrace canal. The developer does not propose to use the existing powerhouse but rather to construct a new powerhouse with a tailrace excavated to the river upstream of the existing powerhouse. Water would be diverted from the river for about 1,200 feet. A site plan and other pertinent information appear on Figure 4-13. Thirteen feet of head are available at the dam. The canal increases the available head to 28 feet. Installed capacities ranging from 500 kW to 3,000 kW were examined. The river is regulated and has several diversions upstream of the site. The 7Q10 flow at the site is 23 cfs and the ABF-1 flow is 192 cfs. The period of record at the nearest USGS gaging station is over 39 years. The tailwater curve for this site was estimated from a flood insurance study of the river in the project area. The headwater and canal headloss curves were developed by performing hydraulic computations.

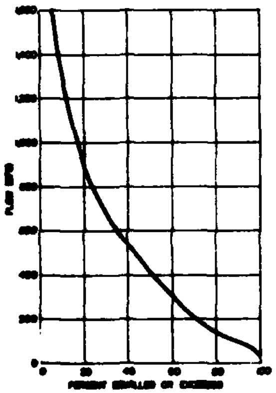
The optimum installed capacity was found to be 1,000 kW. Installation of a small turbine at the dam to utilize minimum flow releases was also considered. The 7Q10 flow (23 cfs) could only drive a 20-kW turbine, which could generate 163 MWh per year at a capital cost of $240,000, or $1,472/MWh. The ABF-1 flow (192 cfs) could drive a 170-kW turbine continuously. This installation would cost approximately $448,000 and would generate about 1,385 MWh per year, resulting in a capital cost per MWh of $324. The ABF-2 flows could support the installation of a 400-kW unit capable of handling flows from 181 cfs to 450 cfs. This installation would cost $782,000 and would generate approximately 2,941 MWh annually, resulting in a capital cost per MWh of $266.

4.10.11 Site K

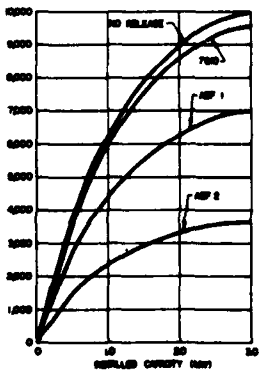
This run-of-river site is located at an existing dam, which is in very good condition. An intake structure at the right dam abutment diverts water into a 1,600-foot-long headrace canal. An intake structure at the canal terminus serves as an inlet for a 250-foot-long steel penstock, which delivers water from the canal to the turbine. The powerhouse is located at the right abutment of another existing dam. Water is diverted from a 2,200-foot-long reach of the river. No new construction would be required, but limited rehabilitation would be necessary for the dam, intake gates,



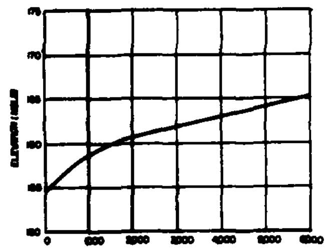
PLAN



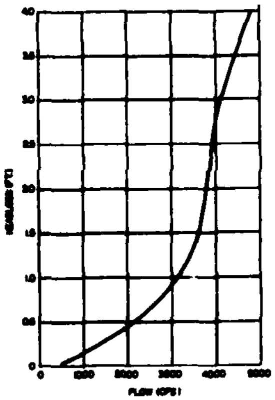
FLOW DURATION CURVE



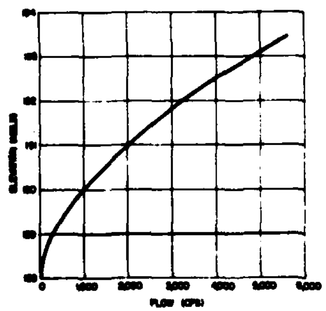
MAIN DEVELOPMENT ENERGY GENERATION CURVES



TAILWATER CURVE



CANAL HEADLOSS CURVE



HEADWATER CURVE

NOTES - SITE J

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	500	1,000	2,000	3,000
CAPITAL COST	[illegible]	[illegible]	[illegible]	[illegible]
NO RELEASE	344	267	302	[illegible]
7Q10	[illegible]	278	316	[illegible]
ABF - 1	487	378	430	[illegible]
ABF - 2	[illegible]	713	[illegible]	[illegible]

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	1,000	1,000	1,000	1,000
	SMALL	0	30	170	400
	TOTAL	1,000	1,030	1,170	1,400
COST	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	$ 240,000	$ 440,000	$ 782,000
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]
AVERAGE ANNUAL ENERGY (MWH)	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	163	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	5,776	5,278
CAPITAL COST PER MEGAWATT HOUR	MAIN	$ 267	$ 278	$ 378	$ 713
	SMALL	0	$1,472	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	[illegible]	30	41	78
	TOTAL		34	40	51
TAXABLE ENTITY	MAIN	[illegible]	40	[illegible]	[illegible]
	TOTAL		46	[illegible]	67

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

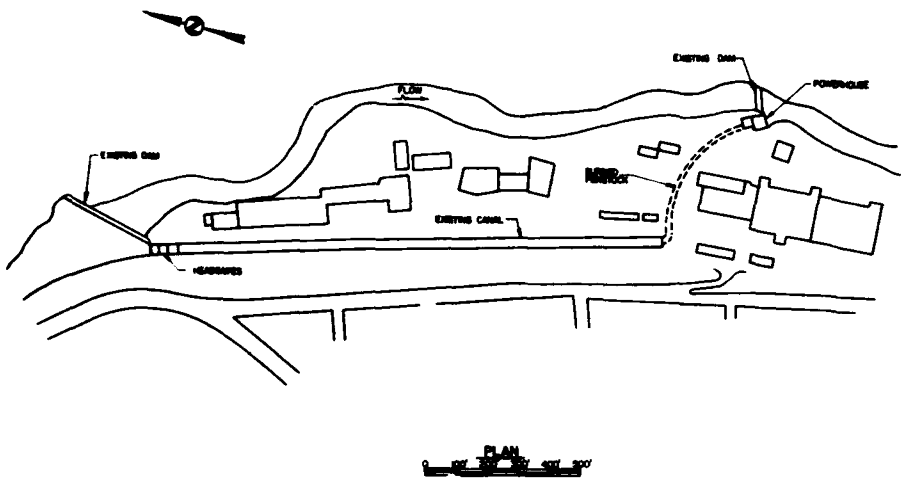
SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

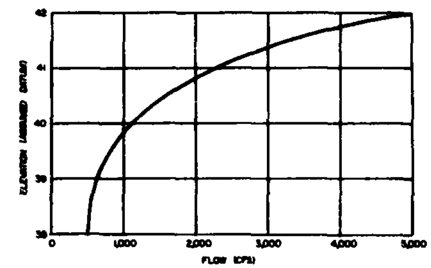
NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE J

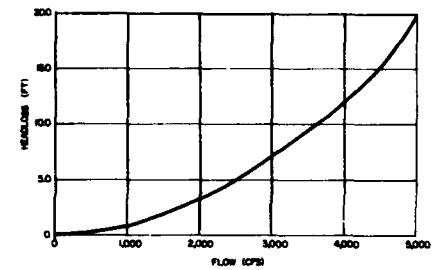
INTERNATIONAL ENGINEERING COMPANY, INC.



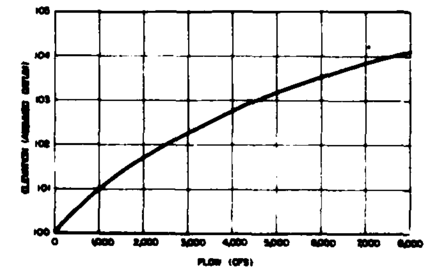
PLAN



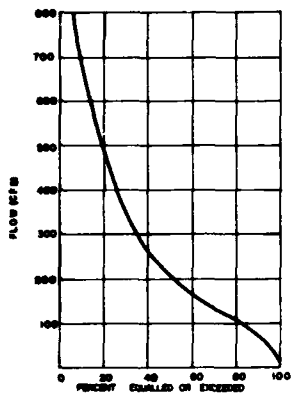
TAILWATER CURVE



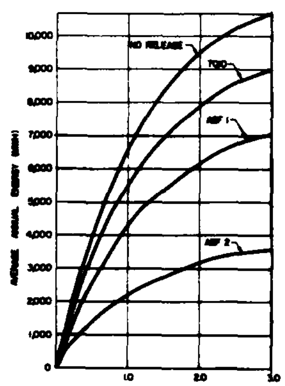
CANAL HEADLOSS CURVE



HEADWATER CURVE



FLOW DURATION CURVE



MAIN DEVELOPMENT
ENERGY GENERATION CURVES

NOTES - SITE K

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	750	1,500	2,000	3,000
CAPITAL COST	$1,208,000	$1,708,000	[illegible]	[illegible]
NO RELEASE	222	206	[illegible]	[illegible]
7Q10	264	246	[illegible]	[illegible]
ABF - 1	[illegible]	319	[illegible]	[illegible]
ABF - 2	[illegible]	643	651	711

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	1,500	1,500	1,500	1,500
	SMALL	0	90	110	[illegible]
	TOTAL	1,500	1,590	1,610	[illegible]
COST	MAIN	$1,708,000	$1,708,000	$1,708,000	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	$1,708,000	[illegible]	[illegible]	[illegible]
AVERAGE ANNUAL ENERGY (MWH)	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	6,230	[illegible]
CAPITAL COST PER MEGAWATT HOUR	MAIN	$206	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	$206	[illegible]	[illegible]	[illegible]

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	22	27	35	67
	TOTAL		29	37	60
TAXABLE ENTITY	MAIN	30	36	46	[illegible]
	TOTAL		39	49	79

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE K

INTERNATIONAL ENGINEERING COMPANY, INC.

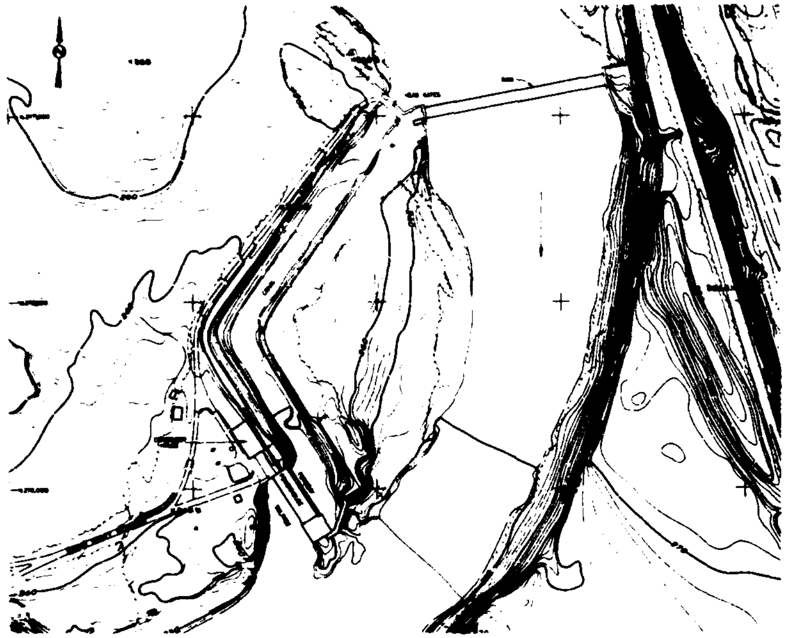
and canal. A site plan is shown on Figure 4-14 along with other pertinent information. Fifteen feet of head are available at the dam. The canal and penstock increase the available head to 62 feet. Installed capacities ranging from 750 kW to 3,000 kW were studied. The river is regulated by flood control structures upstream of the project site. The 7Q10 flow at the site is 49 cfs, and the ABF-1 flow is 109 cfs. The nearest USGS gaging station has a period of record of more than 40 years. The tailwater curve was estimated using information provided by the site developer. The headwater and canal headloss curves were developed by performing hydraulic computations.

The optimum installed capacity was found to be 1,500 kW. Installation of a small turbine at the dam was also considered to use the minimum flow releases to generate energy. The 7Q10 flow (49 cfs) could drive a 50-kW turbine continuously, generating an average of 391 MWh per year. The cost of this installation would be $254,000, resulting in a capital cost per MWh of $650. The ABF-1 flow (109 cfs) could drive a 110-kW turbine continuously, generating an average of 872 MWh annually. The cost of the installation would be $405,000, yielding a capital cost per MWh of $464. The ABF-2 flow could drive an adjustable-blade, 265-kW turbine capable of handling flows from 105 to 275 cfs at a total capital cost of $840,000. The unit would generate an average of 1,846 MWh per year, yielding a capital cost per MWh of $455.

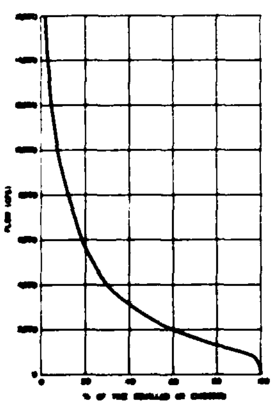
4.10.12 Site L

This run-of-river project is located at an existing rock-filled timber crib dam, which is in poor condition. An intake structure at the right dam abutment diverts flow into a 1,200-foot-long, nearly L-shaped headrace canal. A new powerhouse would be constructed at the terminus of the headrace canal. Water would be diverted from the river for a total of about 1,200 feet. A site plan and other pertinent information appear in Figure 4-15. Twelve feet of head are available at the dam. The canal increases the available head to 16 feet. Installed capacities ranging from 2,000 kW to 8,000 kW were studied. The river is regulated by several flood control structures upstream of the project site. The 7Q10 flow at the site is 670 cfs and the ABF-1 (0.5 cfsm) flow is 1,180 cfs. Hydrology for the site was based on two upstream USGS gaging stations. The period of record at each gage is more than 40 years. The tailwater, headwater, and canal headloss curves were taken from a feasibility study prepared by a consulting engineering firm.

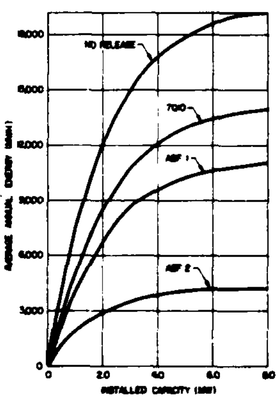
The optimum installed capacity was found to be 2,000 kW. Installation of a small turbine at the dam to utilize the minimum flow releases was also considered. The 7Q10 flow (670 cfs) could drive a 550-kW turbine continuously. The installation would cost $1,546,000 and would generate an average of 4,481 MWh per year. The capital cost per MWh for this installation would be $345. The ABF-1 flow of 1,180 cfs could drive a 1,000-kW turbine continuously, generating an average of 8,147 MWh annually. The cost of the installation would be $1,850,000, resulting in a capital cost per MWh of $227. A 2,400-kW, adjustable-blade turbine could be installed to handle ABF-2 flows generating 18,196 MWh annually with a capital cost of $4,149,000 for a capital cost per MWh of $228.



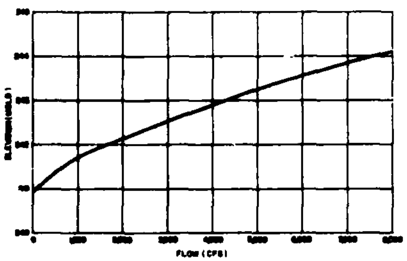
PLAN



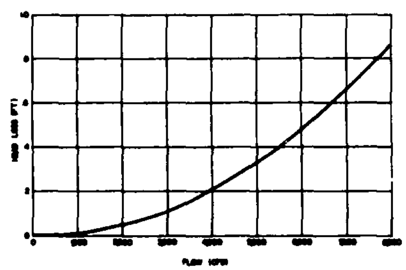
FLOW DURATION CURVE



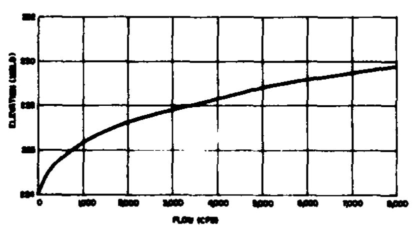
MAIN DEVELOPMENT
ENERGY GENERATION CURVES



TAILWATER CURVE



CANAL HEADLOSS CURVE



HEADWATER CURVE

NOTES - SITE L

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	2,000	4,000	6,000	8,000
CAPITAL COST	$5,[illegible]	$[illegible]	$[illegible]	$[illegible]
NO RELEASE	[illegible]	515	[illegible]	763
7Q10	661	717	[illegible]	[illegible]
ABF - 1	841	906	[illegible]	[illegible]
ABF - 2	1,956	2,235	[illegible]	3,511

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	2,000	2,000	2,000	2,000
	SMALL	0	580	1,000	2,400
	TOTAL	2,000	2,580	3,000	4,400
COST	MAIN	$[illegible]	$[illegible]	$[illegible]	$[illegible]
	SMALL	0	$1,346,000	$[illegible]	$[illegible]
	TOTAL	$[illegible]	$7,171,000	$7,475,000	$[illegible]
AVERAGE ANNUAL ENERGY (MWH)	MAIN	[illegible]	8,506	[illegible]	2,876
	SMALL	0	4,461	8,147	[illegible]
	TOTAL	[illegible]	12,967	[illegible]	21,072
CAPITAL COST PER MEGAWATT HOUR	MAIN	$ [illegible]	$661	$ 841	$1,956
	SMALL	0	$346	$ 227	$ [illegible]
	TOTAL	$ [illegible]	$552	$ 504	$ 464

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	51	72	[illegible]	[illegible]
	TOTAL		60	[illegible]	91
TAXABLE ENTITY	MAIN	[illegible]	[illegible]	121	[illegible]
	TOTAL		80	73	67

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE L

INTERNATIONAL ENGINEERING COMPANY, INC.

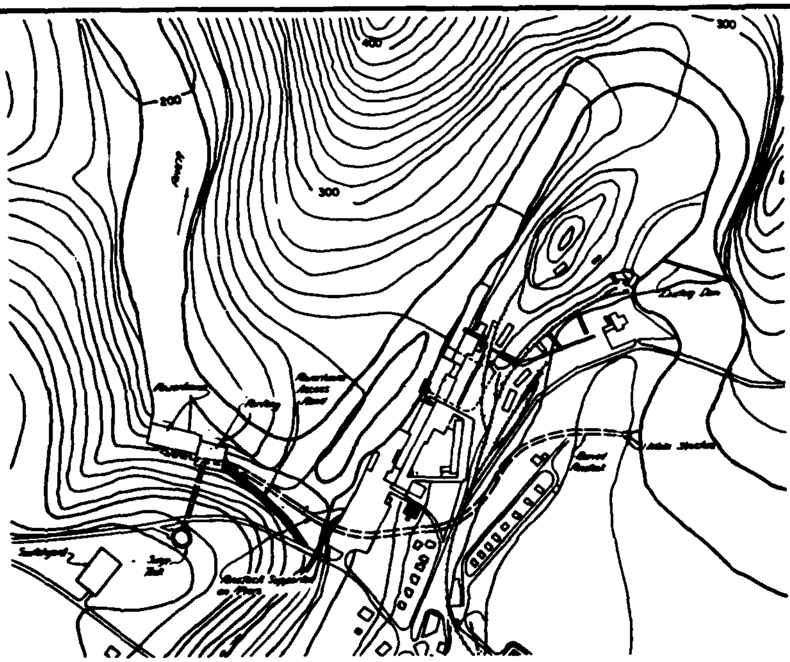
4.10.13 Site M

This run-of-river project is located at an existing dam, which is in good condition. Under the proposed development scheme, an intake structure would be built upstream of the dam on the left bank to divert water into a 2,300-foot-long penstock. A powerhouse would be constructed on the left bank of the river, diverting flow from this river for a total of 4,700 feet. A site plan and other pertinent information appear on Figure 4-16. Twenty-five feet of head are available at the dam. The penstock increases the available head to 110 feet. Installed capacities ranging from 20,000 kW to 40,000 kW were studied. The river is essentially free flowing, although it has small impoundments and industrial diversions upstream. The 7Q10 flow at the site is 93 cfs and the ABF-1 flow is 400 cfs. The period of record at the nearest USGS gaging station is more than 50 years. The tailwater and headwater curves were taken from an appraisal study prepared for the developer by a consulting engineer.

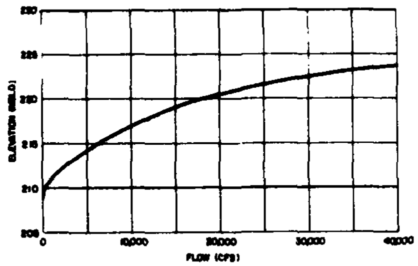
The optimum installed capacity was found to be 20,000 kW. Use of a small turbine at the dam to utilize minimum flow releases for power generation was also considered. The 7Q10 flow (93 cfs) could drive a 160-kW turbine continuously. The installation would cost $384,000, would generate a yearly average of 1,271 MWh, and would have a capital cost per MWh of $302. A turbine sized to use the ABF-1 flow of 400 cfs would not operate continuously. However, an adjustable-blade, 1,300-kW turbine could be installed to operate over a greater flow range (300 to 750 cfs). The same installation could be recommended for the ABF-2 flows. Such an installation would cost $1,860,000 and would generate an average of 9,559 MWh per year, for a capital cost per MWh of $195.

4.11 SUMMARY OF RESULTS

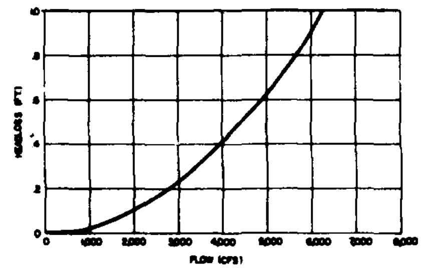
Tables 4-1 through 4-3 summarize the results of the study. Table 4-1 reflects the effect of the various flow regimes upon the quantity of energy produced and the cost per MWh of energy. Table 4-2 is a chart which summarizes the energy generation studies, while Table 4-3 summarizes the economic studies.



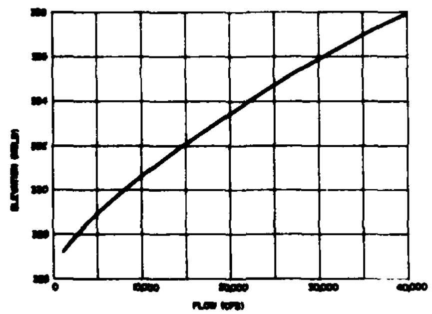
PLAN



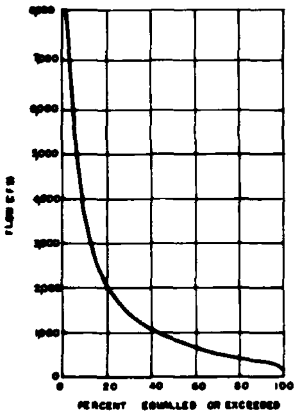
TAILWATER CURVE



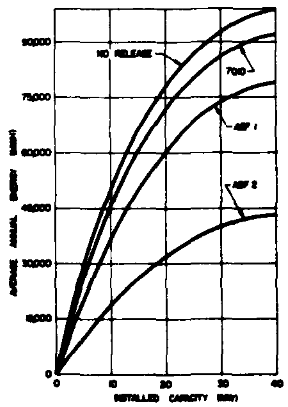
PENSTOCK HEADLOSS CURVE



HEADWATER CURVE



FLOW DURATION CURVE



MAIN DEVELOPMENT
ENERGY GENERATION CURVES

NOTES - SITE M

CAPITAL COST PER MWH - PROPOSED DEVELOPMENT				
INSTALLED CAPACITY (KW)	20,000	25,000	30,000	40,000
CAPITAL COST	[illegible]	[illegible]	[illegible]	[illegible]
NO RELEASE	296	[illegible]	[illegible]	[illegible]
7Q10	[illegible]	[illegible]	[illegible]	[illegible]
ABF - 1	[illegible]	[illegible]	[illegible]	[illegible]
ABF - 2	717	734	[illegible]	[illegible]

SUMMARY					
RELEASE POLICY		NO RELEASE	7Q10	ABF - 1	ABF - 2
INSTALLED CAPACITY (KW)	MAIN	20,000	20,000	20,000	20,000
	SMALL	0	160	1,300	1,300
	TOTAL	20,000	20,160	21,300	21,300
COST	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	[illegible]	[illegible]	[illegible]	[illegible]
AVERAGE ANNUAL ENERGY (MWH)	MAIN	78,494	[illegible]	[illegible]	[illegible]
	SMALL	0	[illegible]	[illegible]	[illegible]
	TOTAL	78,494	[illegible]	[illegible]	[illegible]
CAPITAL COST PER MEGAWATT HOUR	MAIN	$ 296	$ [illegible]	$ [illegible]	$ 717
	SMALL	0	$ [illegible]	$ [illegible]	$ [illegible]
	TOTAL	$ 296	$ [illegible]	$ [illegible]	$[illegible]

INITIAL VALUE OF ENERGY REQUIRED TO MEET DESIGNATED FINANCIAL CRITERIA (MILLS/KWH)					
		NO RELEASE	7Q10	ABF - 1	ABF - 2
TAX - EXEMPT ENTITY	MAIN	[illegible]	[illegible]	[illegible]	70
	TOTAL		[illegible]	[illegible]	[illegible]
TAXABLE ENTITY	MAIN	[illegible]	[illegible]	[illegible]	[illegible]
	TOTAL		[illegible]	[illegible]	[illegible]

MAIN - INDICATES THE DEVELOPMENT SELECTED BASED ON CAPITAL COST PER MEGAWATT HOUR

SMALL - INDICATES THE SMALL TURBINE DEVELOPMENT LOCATED AT THE DAM

TOTAL - INDICATES THE COMBINATION OF MAIN AND SMALL

NEW ENGLAND RIVER BASINS COMMISSION

CASE STUDY SITE M

CONSULTING ENGINEERS
INTERNATIONAL ENGINEERING COMPANY, INC.

Table 4-1

Summary of Energy Generation

Site	Head (ft) PH	Head (ft) Dam	Installed Capacity (kW)	Diversion Length (ft)	Average Annual Flow (cfs)	Condition Dam	Condition DCS	Condition PH	Average Annual Energy (MWh) – No Minimum Release	Without Small Turbine – With Small Turbine 7Q10	ABF-1	ABF-2	Effect of Small Turbine on Energy Generation Compared to No Minimum Release 7Q10	ABF-1	ABF-2	Percent Change in Energy Generation Due to Minimum Flow Release Policy 7Q10	ABF-1	ABF-2
A	44	12	1,000	750	172	N	N	N	3,101	2,981 3,014	2,692 2,814	1,150 1,272	-	-	-	-4 -3	-13 -9	-63 -59
B	24	16	1,000	720	934	E	E	N	6,287	5,160 6,276	3,713 7,003	1,590 4,875	-	+	-	-18 0	-41 +11	-75 -22
C	24	12	1,000	1,200	569	M	N	N	5,883	5,705 5,819	4,501 5,479	2,528 3,506	-	-	-	-3 -1	-23 -7	-57 -40
D	12	6	500	2,200	562	E	E	M	2,744	2,341 2,545	1,957 2,364	1,009 1,416	-	-	-	-15 -7	-29 -14	-63 -48
E	38	38	8,000	0	2,024	N	-	N	35,348	34,693 35,687	30,087 43,426	26,062 39,401	+	+	+	-1 +4	-12 +26	-24 +15
F	18	10	500	700	612	E	E	M	3,087	2,910 3,032	2,151 3,112	1,153 3,353	-	+	+	-6 -2	-30 +1	-63 +9
G	23	12	500	240	143	E	E	E	1,803	1,614 1,736	1,458 1,662	804 1,008	-	-	-	-10 -4	-19 -8	-55 -44
H	30	19	3,000	4,700	654	N	M	N	10,949	10,011 10,484	7,719 9,348	3,927 7,436	-	-	-	-9 -4	-30 -15	-64 -32
I	68	16	10,000	12,000	2,316	M	N	N	70,683	31,346 41,936	52,093 57,592	26,461 39,840	-	-	-	-56 -41	-26 -19	-63 -44
J	28	13	1,000	1,200	642	E	N	N	6,247	5,994 6,157	4,405 5,790	2,337 5,278	-	-	-	-4 -1	-29 -7	-63 -16
K	62	5	1,500	2,200	349	E	E	E	8,326	6,937 7,328	5,358 6,230	2,786 4,632	-	-	-	-17 -12	-36 -25	-67 -44
L	16	12	2,000	1,200	4,154	M	E	N	11,983	8,506 12,987	6,686 14,833	2,876 21,072	+	+	+	-29 +8	-44 +24	-76 +75
M	110	25	20,000	4,700	1,515	E	N	N	78,454	72,212 73,483	60,815 70,374	32,349 41,908	-	-	-	-8 -6	-22 -10	-59 -47

DCS – Diversion Conveyance Structure
PH – Powerhouse

E – Existing Structure
M – Major Rehabilitation Required
N – New Construction

Table 4-2

Summary of Cost-Energy Ratios

Site	Head (ft)		Installed Capacity (kW)	Diversion Length (ft)	Average Annual Flow (cfs)	Condition			Cost-Energy Ratio ($/MWh)	Without Small Turbine - With Small Turbine			Effect of Small Turbine on Cost-Energy Ratio			Change in Cost-Energy Ratio Due to Flow Release Policy		
	PH	Dam				Dam	DCS	PH	No Minimum Release	7Q10	ABF-1	ABF-2	7Q10	ABF-1	ABF-2	7Q10	ABF-1	ABF-2
A	44	12	1,000	750	172	N	M	M	1,490	1,550	1,716	4,014	-	+	+	+4	+15	+170
										1,593	1,701	3,764				+7	+14	+153
B	24	16	1,000	720	934	E	E	N	373	454	631	1,475	+	+	+	+22	+69	+295
										441	442	635				+18	+18	+70
C	24	12	1,000	1,200	569	M	N	N	567	585	741	1,320	-	+	+	+3	+31	+133
										603	678	1,060				+6	+20	+87
D	12	6	500	2,200	562	E	E	M	470	551	659	1.278	-	-	+	+17	+40	+172
										615	715	1,194				+31	+52	+154
E	38	38	8,000	0	2,024	N	-	N	501	517	589	680	+	+	+	+2	+18	+36
										507	468	516				+1	-7	+3
F	18	10	500	700	612	E	E	M	394	418	565	1,055	-	+	+	+6	+43	+168
										441	513	573				+12	+30	+45
G	23	12	500	240	143	E	E	E	643	719	796	1,443	-	-	+	+12	+24	+124
										752	810	1,335				+17	+26	+108
H	30	19	3,000	4,700	654	N	M	N	590	645	837	1,645	+	+	+	+9	+42	+179
										641	778	1,025				+9	+32	+74
I	68	16	10,000	12,000	2,316	M	N	N	254	572	344	678	+	+	+	+125	+35	+167
										470	332	507				+85	+31	+100
J	28	13	1,000	1,200	642	E	N	N	267	278	378	713	-	+	+	+4	+42	+167
										310	365	464				+16	+37	+74
K	62	5	1,500	2,200	349	E	E	E	205	246	319	613	-	-	+	+20	+57	+200
										268	339	550				+31	+65	+168
L	16	12	2,000	1,200	4,154	M	E	N	469	661	841	1,956	+	+	+	+41	+79	+317
										552	504	464				+18	+7	-1
M	110	25	20,000	4,700	1,515	E	N	N	296	321	381	717	0	+	+	+8	+29	+142
										321	356	598				+3	+20	+102

DCS - Diversion Conveyance Structure
PH Powerhouse

E - Existing Structure
M - Major Rehabilitation Required
N - New Construction

Table 4-3

Summary of Initial Value of Energy Required to Meet Designated Financial Criteria

Site	Head (ft)		Installed Capacity (kW)	Diversion Length (ft)	Average Annual Flow (cfs)	Condition			Initial Value of Energy Required to Meet Designated Financial Criteria (Mills/kWh)							
									Tax-Exempt Entity Without Small Turbine / With Small Turbine				Taxable Entity Without Small Turbine / With Small Turbine			
	PH	Dam				Dam	DCS	PH	No Minimum Release	7Q10	ABF-1	ABF-2	No Minimum Release	7Q10	ABF-1	ABF-2
A	44	12	1,000	750	172	N	N	N	163	170	188	603	215	224	248	580
										174	186	412		230	246	544
B	24	16	1,000	720	934	E	E	N	41	50	69	162	54	66	91	213
										48	48	70		64	64	92
C	24	12	1,000	1,200	569	M	N	N	62	64	81	145	82	84	107	191
										66	74	116		87	98	153
D	12	6	500	2,200	562	E	E	M	51	60	72	140	68	80	95	185
										67	78	131		89	103	172
E	38	38	8,000	0	2,024	N	-	N	55	57	64	74	72	75	85	98
										56	51	57		73	68	75
F	18	10	500	700	612	E	E	M	43	46	62	116	57	60	82	152
										48	56	63		64	74	83
G	23	12	500	240	143	E	E	E	70	79	87	158	93	104	115	208
										82	89	146		109	117	193
H	30	19	3,000	4,700	654	N	M	N	65	71	92	180	85	93	121	238
										70	85	112		93	112	148
I	68	16	10,000	12,000	2,316	M	N	N	28	63	38	74	37	83	50	98
										51	36	56		68	48	73
J	28	13	1,000	1,200	642	E	N	N	29	30	41	78	39	40	55	103
										34	40	51		45	53	67
K	62	5	1,500	2,200	349	E	E	E	22	27	35	67	30	36	46	89
										29	37	60		39	49	79
L	16	12	2,000	1,200	4,154	M	E	N	51	72	92	214	68	95	121	282
										60	55	51		80	71	67
M	110	25	20,000	4,700	1,515	E	N	N	32	35	42	79	43	46	73	103
										35	39	65		46	51	86

DCS - Diversion Conveyance Structure
PH - Powerhouse

E - Existing Structure
M - Major Rehabilitation Required
N - New Construction

SECTION 5

CONCLUSIONS

5.1 POTENTIAL OCCURRENCE OF MINIMUM FLOW CONFLICTS

Minimum flow releases have no impact upon sites that operate in the run-of-river mode and have no diversions. However, only 20 percent of the sites listed on the inventory fit this description. Therefore, if flow releases are required at the dams, the potential for conflict exists at 80 percent of the sites.

If the distance from the dam within which the releases must be made is increased, the incidence of conflict will decrease. For example, sites that have diversions less than 300 feet account for a total of 46 percent of all the sites. If minimum flow releases were allowed to be made at a powerhouse located anywhere within this 300-foot limit, then the "conflict incidence" would decrease to 54 percent.

Fourteen percent of the sites are considered to be peaking operation sites. These sites would also cause conflict due to the store and release nature of peaking operation.

5.2 IMPACT OF MINIMUM FLOW RELEASE POLICIES ON PROJECT ECONOMICS

The direct effect of the minimum flow release policies is to reduce the energy that can be generated at a site, when releases must be made at the dam. The reduction in energy generation, in turn, increases the cost of the energy generated because the same capital cost for a given installed capacity must be spread over fewer kilowatts. Some of this lost energy can be recaptured by installing small turbines at the required point of release. However, this increases the capital cost of the project.

The flow of water is proportional to the area of the drainage basin. Those sites with large drainage basins have correspondingly larger flows, hence more water with which to generate energy. The percentage of flow lost to minimum flow releases will not vary much from the percentage at sites commanding small drainage basins; however, the quantity of flow will be substantial by comparison. The large-flow site enjoys an advantage because more equipment options are available to generate energy with the required releases. For example, a site with 12 feet of head and a 7Q10 flow of 5 cfs has little chance of generating energy at a reasonable cost with this flow. However, a site with 12 feet of head and a 7Q10 flow of 500 cfs can probably generate power using the equipment of any of several manufacturers, with consequent savings in equipment costs.

Available head is another important factor in determining the ability of a site to economically generate energy. As head increases at a given flow, energy generation also increases; while equipment, and hence powerhouse, costs remain substantially constant. Therefore, the cost of energy decreases, provided no civil works costs are required to obtain the

additional head. For the case studies, civil costs were expended to realize the maximum economic head at each site. That is, the head has been increased by the use of penstocks and/or headrace and tailrace channel excavations until the increased costs just offset the increased benefits.

The effect of each flow regime upon the case study sites is discussed in the following subsections.

5.2.1 No Minimum Flow Release

The no-minimum-flow-release regime does not require any minimum flow releases. This allows a project to generate the maximum amount of energy for a given installed capacity. The regime does not imply that water will never be spilled over a dam. For example, water will be spilled until flow in the river becomes great enough to drive a turbine for a reasonable amount of time. This flow is determined by the minimum gate setting of the smallest turbine installed. Furthermore, it is not economical to install sufficient capacity at a hydro site to generate energy using the peak river flows. This is particularly true for smaller sites. Therefore, peak river flows that exceed the discharge capacity of the installed turbines are also spilled.

5.2.2 7Q10 Minimum Flow Release

Release of the 7Q10 flow resulted in a decrease in energy generated by the proposed development of from 1 to 56 percent and a corresponding increase in capital cost per MWh of from 2 to 125 percent. The capital cost per MWh was reduced under this policy by use of small turbines at those sites having 16 feet or more of head available at the dam. At 12 feet of head, use of small turbines is marginal. At less than 12 feet of head, use of small turbines appears to be of no economic benefit to the project.

The use of small turbines appears to become more attractive under this flow regime as the amount of regulation at a site increases. At a highly regulated site, the 7Q10 is higher in terms of cfs per square mile of drainage basin than for a similar size drainage basin with no regulation. Thus, minimum release requirements tend to be larger as a percentage of average annual flow. Since a higher percentage of the flow is being lost, the impact on project feasibility is greater. On the other hand, there is more flow to run a turbine at the dam site.

5.2.3 Aquatic Base Flow Releases

The effect of the ABF releases on hydro generating capacity is usually more severe than 7Q10 releases. The minimum ABF flow regime resulted in a decrease in energy from 12 to 44 percent without consideration of the use of small turbines to generate power from the releases made at the dam. Capital costs increased from 18 to 79 percent.

The ABF-2 minimum flow release, as defined for this study, reduced the energy generation at the case study sites anywhere from 24 to 76 percent, with the average around 55 percent. The use of small turbines for the releases resulted in only a minor improvement over these losses. Cutting energy production in half will double the cost of energy produced at a site for a given installed capacity. Such an extreme impact upon a project usually results in the project being unfeasible. However, it should be pointed out that the FWS would probably not require releases as extreme as the ABF-2 flows used in this study.

5.2.4 *Use of Small Turbines*

Under the 7Q10 flow regime, small turbine installations were found to improve the economic viability of a project, provided the available head at the dam was at least 16 feet. Projects with less than 16 feet of head at the dam were found not to benefit from a small turbine installation. As would be expected, no project employing a small turbine at the dam for 7Q10 flows was found to be more attractive than the same project under the no-minimum-flow-release regime.

Use of small turbines under the ABF-1 policy improved the economic viability of nearly all projects over the ABF-1 projects without the turbines. All projects improved substantially with the use of small turbines under the ABF-2 regime.

5.3 CAPABILITY OF PROJECTS TO ACCOMMODATE MINIMUM FLOW REQUIREMENTS

The ability of any business to absorb losses or a reduction in output depends in many instances on the size of the business. This is quite true for hydro development. Small hydro projects are usually very marginal investments, especially during the first years of operation. To add additional costs or to limit the amount of energy a small project can generate usually prevents development. Larger projects are usually more able to handle these impacts. Although larger projects normally have larger minimum flow releases, these larger releases are typically better suited for driving turbines, which allows the larger projects to recoup a portion of the energy production that would otherwise be lost.

Peaking plants are affected somewhat differently by minimum flow release requirements. Many peaking projects are larger than 5,000 kW and in a better position to justify the installation of small turbines to handle minimum flow releases. However, the energy generated by these small turbines would be worth significantly less than the peaking energy the released water could have generated.

Table 5-1 presents the initial value of energy necessary for a project to meet the financial criteria described in Section 4.9. The shaded areas indicate which projects are not feasible at an initial value of energy of 50 mills per kWh. Under the no minimum flow release policy, six of the case study projects are feasible when developed by tax exempt entities while only four are feasible when developed by taxable entities. Under the 7Q10 policy, five sites would be feasible for development by tax exempt entities, while three sites would be feasible for development by taxable

Table 5-1

Feasible Projects When the Initial Value of Energy is 50 Mills/kWh

Site	Head (ft)		Installed Capacity (kW)	Diversion Length (ft)	Average Annual Flow (cfs)	Condition			Initial Value of Energy Required to Meet Designated Financial Criteria (Mills/kWh)							
									Tax-Exempt Entity	Without Small Turbine With Small Turbine			Taxable Entity	Without Small Turbine With Small Turbine		
	PH	Dam				Dam	DCS	PH	No Minimum Release	7Q10	ABF-1	ABF-2	No Minimum Release	7Q10	ABF-1	ABF-2
A	44	12	1,000	750	172	N	N	N								
B	24	16	1,000	720	934	E	E	N	41	50 48	48					
C	24	12	1,000	1,200	569	M	N	N								
D	12	6	500	2,200	562	E	E	M								
E	38	38	8,000	0	2,024	N	-	N								
F	18	10	500	700	612	E	E	M	43	46 48						
G	23	12	500	240	143	E	E	E								
H	30	19	3,000	4,700	654	N	M	N								
I	68	16	10,000	12,000	2,315	M	N	N	28		38 36		37		50 48	
J	28	13	1,000	1,200	642	E	N	N	29	30 34	41 40		39	40 45		
K	62	5	1,500	2,200	349	E	E	E	22	27 29	35 37		30	36 39	46 49	
L	16	12	2,000	1,200	4,154	M	E	N								
M	110	25	20,000	4,700	1,515	E	N	N	32	35 35	42 39		43	46 46		

DCS – Diversion Conveyance Structure
PH – Powerhouse

E – Existing Structure
M – Major Rehabilitation Required
N – New Construction

entities. The use of small turbines does not increase or decrease the number of feasible sites for either developer type under the 7Q10 minimum release policy. Under the ABF-1 policy, four sites are feasible for development by tax exempt entities while only two sites are feasible for development by taxable entities. The use of small turbines decreases the number of sites feasible for a tax exempt entity to develop from five to four, but results in no change in the number of site feasible for development by taxable entities. No sites are feasible for development under the ABF-2 policy when the initial value of energy is 50 mills/kWh.

Table 5-2 presents the same data as Table 5-1 with shaded areas indicating the projects which are not feasible for an initial value of energy of 70 mills per kWh. Under the no minimum release scenario, 12 projects are feasible for development by a tax exempt entity and eight projects are feasible for development by a taxable entity. Under the 7Q10 policy, nine projects are feasible for development by a tax exempt entity while five are feasible for a taxable entity. The use of small turbines increases this number to eleven for tax exempt entities and six for taxable entities. Under the ABF-1 policy, six projects are feasible for tax exempt development while four projects are feasible for development by a taxable entity. The use of small turbines increases this number to eight for tax exempt entities and six for taxable entities.

Under the ABF-2 policy, two projects are feasible for development by tax exempt entities while none are feasible for development by taxable entities. The use of small turbines increases this number to eight for tax exempt and two for taxable entities.

Table 5-3 also presents the same data as Table 5-1, however, the shaded areas indicate the projects which are not feasible at an initial value of energy of 90 mills per kWh rather than 50 mills per kWh. Under the no minimum flow release policy, twelve projects are feasible for tax exempt entities while eleven projects are feasible for taxable entities. Under the 7Q10 policy, twelve projects are feasible for development by tax exempt entities while nine are feasible for development by taxable entities. The use of small turbines does not change the number of projects feasible for tax exempt entities, but increases the number of feasible projects to ten for taxable entities. Under the ABF-1 policy, ten projects are feasible for tax exempt entities while six are feasible for taxable entities. The use of small turbines increases this number to twelve for tax exempt entities and eight for taxable entities. Under the ABF-2 policy, five projects are feasible for development by tax exempt entities, While nine are feasible for taxable entities. The use of small turbines increases this number to eight for tax exempt and five for taxable entities.

5.4 EFFECT OF MINIMUM FLOW REQUIREMENTS UPON OPERATING OBJECTIVES

Minimum flow requirements will not have a large impact upon the operating objectives of a run-of-river project. The turbine will operate less. Annual energy output will decrease with an increase in minimum flow releases. Decreased energy output also results in less financial return to the project developers.

Table 5-2

Feasible Projects When the Initial Value of Energy is 70 Mills/kWh

Site	Head (ft)		Installed Capacity (kW)	Diversion Length (ft)	Average Annual Flow (cfs)	Condition			Initial Value of Energy Required to Meet Designated Financial Criteria (Mills/kWh)							
									Tax-Exempt Entity	Without Small Turbine With Small Turbine			Taxable Entity	Without Small Turbine With Small Turbine		
	PH	Dam				Dam	DCS	PH	No Minimum Release	7Q10	ABF-1	ABF-2	No Minimum Release	7Q10	ABF-1	ABF-2
A	44	12	1,000	750	172	N	N	N								
B	24	16	1,000	720	934	E	E	N	41	50 48	48	70	54	66 64	64	
C	24	12	1,000	1,200	569	M	N	N	62	64 66						
D	12	6	500	2,200	562	E	E	M	51	60 67			68			
E	38	38	8,000	0	2,024	N	-	N	55	57 56	64 51	57			68	
F	18	10	500	700	612	E	E	M	43	46 48	62 56	63	57	60 64		
G	23	12	500	240	143	E	E	E	70							
H	30	19	3,000	4,700	654	N	M	N	65	70						
I	68	16	10,000	12,000	2,316	M	N	N	28	63 51	38 36	56	37	68	50 48	
J	28	13	1,000	1,200	642	E	N	N	29	30 34	41 40	51	39	40 45	55 53	67
K	62	5	1,500	2,200	349	E	E	E	22	27 29	35 37	67 60	30	36 39	46 49	
L	16	12	2,000	1,200	4,154	M	E	N	51	60	55	51	68			[illegible]
M	110	25	20,000	4,700	1,515	E	N	N	32	35 35	42 39	79 65	43	46 46	51	

DCS - Diversion Conveyance Structure
PH - Powerhouse

E - Existing Structure
M - Major Rehabilitation Required
N - New Construction

Table 5-3

Feasible Projects When the Initial Value of Energy is 90 Mills/kWh

Site	Head (ft)		Installed Capacity (kW)	Diversion Length (ft)	Average Annual Flow (cfs)	Condition			Initial Value of Energy Required to Meet Designated Financial Criteria (Mills/kWh)							
									Tax-Exempt Entity	Without Small Turbine / With Small Turbine			Taxable Entity	Without Small Turbine / With Small Turbine		
	PH	Dam				Dam	DCS	PH	No Minimum Release	7Q10	ABF-1	ABF-2	No Minimum Release	7Q10	ABF-1	ABF-2
A	44	12	1,000	750	172	N	N	N	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
B	24	16	1,000	720	934	E	E	N	41	50 / 48	69 / 48	[illegible] / 70	54	66 / 64	[illegible] / 64	[illegible]
C	24	12	1,000	1,200	569	N	N	N	62	64 / 66	81 / 74	[illegible]	82	84 / 87	[illegible]	[illegible]
D	12	6	500	2,200	562	E	E	M	51	60 / 67	72 / 78	[illegible]	68	80 / 89	[illegible]	[illegible]
E	38	38	8,000	0	2,024	N	-	N	55	57 / 56	64 / 51	74 / 57	72	75 / 73	85 / 68	[illegible] / 75
F	18	10	500	700	612	E	E	M	43	46 / 48	62 / 56	[illegible] / 63	57	60 / 64	82 / 74	[illegible]
G	23	12	500	240	143	E	E	E	70	79 / 82	87 / 89	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
H	30	19	3,000	4,700	654	N	M	N	65	71 / 70	[illegible] / 85	[illegible]	85	[illegible]	[illegible]	[illegible]
I	68	16	10,000	12,000	2,316	M	N	N	28	63 / 51	38 / 36	74 / 56	37	83 / 68	50 / 48	[illegible] / 73
J	28	13	1,000	1,200	642	E	N	N	29	30 / 34	41 / 40	78 / 51	39	40 / 45	55 / 53	[illegible] / 67
K	62	5	1,500	2,200	349	E	E	E	22	27 / 29	35 / 37	67 / 60	30	36 / 39	46 / 49	89 / 79
L	16	12	2,000	1,200	4,154	M	E	N	51	72 / 60	[illegible] / 55	[illegible] / 51	68	[illegible] / 80	[illegible] / 71	[illegible] / 67
M	110	25	20,000	4,700	1,515	E	N	N	32	35 / 35	42 / 39	79 / 65	43	46 / 46	73 / 51	[illegible] / 86

DCS – Diversion Conveyance Structure
PH – Powerhouse

E – Existing Structure
M – Major Rehabilitation Required
N – New Construction

Decreased hydroelectric energy output on a regional basis means that oil-fired energy deplacement will not be as great.

5.5 DISCUSSION OF GENERIC MEASURES

From the standpoint of energy generation, generic measures are not satisfactory due to the site-specific nature of hydro development. The effect of the release of 7Q10 or aquatic base flows on the generation varies with the size of the project and the amount of regulation.

5.6 ALTERNATIVES FOR MEETING MINIMUM FLOW REQUIREMENTS

Projects with less than 16 feet of head available at the dam have few alternatives, if releases must be made at the dam. Projects located on large, highly regulated rivers or having large drainage basins, may have minimum flow releases large enough to justify installation of a turbine at the dam. Projects greater than 5,000 kW can usually benefit from the installation of a small turbine to handle the releases. This is especially true for peaking projects

Minimum flow regimes, as currently formulated, significantly impact hydroelectric projects because they are sustained releases. Few hydroelectric projects use all the water in a river all the time. Careful consideration should be given to the amount of water actually spilled by a typical hydroelectric project operating under a 7Q10 flow regime because of minimum/maximum equipment discharges.

APPENDIX A

UNITED STATES
DEPARTMENT OF THE INTERIOR
FISH AND WILDLIFE SERVICE
One Gateway Center [illegible]
NEWTON CORNER, MASSACHUSETTS [illegible]

INTERIM
REGIONAL POLICY
FOR NEW ENGLAND STREAM FLOW RECOMMENDATIONS

A. Purpose

The U.S. Fish and Wildlife Service (USFWS) recognizes that immediate development of alternative energy supplies is a high national priority. We further recognize that hydroelectric developments are among the most practical near-term alternatives and that environmental reviews may have delayed expeditious licensing of some environmentally sound projects. A purpose of this policy is to identify those projects that do not threaten nationally important aquatic resources so that permits or licenses for those projects can be expeditiously issued without expensive, protracted environmental investigations.

This directive establishes Northeast Regional (Region 5) policy regarding USFWS flow recommendations at water projects in the New England Area. The policy is primarily for application to new or renewal hydroelectric projects but should also be used for water supply, flood control and other water development projects. The intent of this policy is to encourage releases that perpetuate indigenous aquatic organisms.

B. Background

The USFWS has used historical flow records for New England to describe stream flow conditions that will sustain and perpetuate indigenous aquatic fauna. Low flow conditions occurring in August typically result in the most metabolic stress to aquatic organisms, due to high water temperatures and diminished living space, dissolved oxygen, and food supply. Over the long term, stream flora and fauna have evolved to survive these periodic adversities without major population changes. The USFWS has therefore designated the median flow for August as the Aquatic Base Flow (ABF) 1/. The USFWS has assumed that the ABF will be adequate throughout the year, unless additional flow releases are necessary for fish spawning and incubation. We have determined that flow releases equivalent to historical median flows during the spawning and incubation periods will protect critical reproductive functions.

1/ Aquatic Base Flow as used here should not be confused with the hydrologic base flow, which usually refers to the minimum discharge over a specified period.

C. <u>Directive</u>

1. USFWS personnel shall use this standard procedure when reviewing, providing planning advice for and/or commenting on water development projects in New England Area.

2. USFWS personnel shall encourage applicants, project developers and action agencies to independently assess the flow releases needed by indigenous organisms on a case-by-case basis, and to present project-specific recommendations to the USFWS as early in the planning process as possible.

3. USFWS personnel shall recommend that the instantaneous flow releases for each water development project be sufficient to sustain indigenous aquatic organisms throughout the year. USFWS flow recommendations are to be based on historical stream gaging records as described below, unless Section 6 herein applies.

a. Where a miniumum of 25 years of U.S. Geological Survey (USGS) gaging records exist at or near a project site on a river that is basically free-flowing, the USFWS shall recommend that the ABF release for all times of the year be equivalent to the median August flow for the period of record unless superceded by spawning and incubation flow recommendations. The USFWS shall recommend flow releases equivalent to the historical median stream flow throughout the applicable spawning and incubation periods.

b. For rivers where inadequate flow records exist or for rivers regulated by dams or upstream diversions, the USFWS shall recommend that the aquatic base flow (ABF) release be 0.5 cubic feet per second per square mile of drainage (cfsm), as derived from the average of the median August monthly records for representative New England streams.2/ This 0.5 cfsm recommendation shall apply to all times of the year, unless superceded by spawning and incubation flow recommendations. The USFWS shall recommend flow releases of 1.0 cfsm in the fall/winter and 4.0 cfsm in the spring for the entire applicable spawning and incubation periods.

4. The USFWS shall recommend that when inflow immediately upstream of a project falls below the flow release prescribed for that period, the outflow be made no less than the inflow, unless Section 6 herein applies.

5. The USFWS shall recommend that the prescribed instantaneous ABF be maintained at the base of the dam in the natural river channel, unless Section 6 herein applies.

2/The ABF criterion of 0.5 cfsm and the spawning and incubation flow criteria of 1.0 and 4.0 cfsm were derived from studies of 48 USGS gaging stations on basically unregulated rivers throughout New England. Each gaging station had a drainage area of at least 50 square miles, negligible effects from regulation, and a minimum of 25 years of good to excellent flow records. On the basis of 2,245 years of record, 0.5 cfsm was determined to be the average median August monthly flow. The flows of 1.0 and 4.0 cfsm represent the average of the median monthly flows during the fall-winter and spring spawning and incubation periods.

6. USFWS shall review alternative proposals for the flow release locations, schedules and supplies, provided such proposals are supported by biological justification. If such proposals are found by USFWS to afford adequate protection to aquatic biota, USFWS personnel may incorporate all or part of such proposals into their recommendations.

7. USFWS personnel shall forward their recommendations to the Regional Director for concurrence (prior to release) whenever such recommendations would differ from the median historical flow(s) otherwise computed in accordance with Sections 3a and 3b above. For projects with lengthy headraces, tailraces, penstocks, canals or other diversions, Regional Director's concurrence need not be obtained on flow recommendations applicable to the river segment between the dam and downstream point of confluence of the discharge with the initial watercourse.

D. Exemptions

On projects where the USFWS has written agreements citing 0.2 cfsm as a minimum flow, the USFWS shall not recommend greater flows during the lifetime of the current project license. Three hydro-electric projects at Vernon, Bellow Falls and Wilder, Vermont, currently qualify in this regard.

E. Previous Directives

The Regional Director's memorandum dated April 11, 1980 and attached New England Area Flow Regulation Policy are hereby rescinded.

2/13/81 Date

Howard N. Larsen
Regional Director